EIGHTY-THIRD REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 1993, through December 31, 1993

* John E. Thomas, Chairman

William W. Redman, Jr., Commissioner

Charles H. Hughes, Commissioner

Laurence A. Cobb, Commissioner

Allyson K. Duncan, Commissioner

* Ralph A. Hunt, Commissioner

* Judy Hunt, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Mrs. Geneva S. Thigpen
Post Office Box 29510
Raleigh, North Carolina 27626-0510

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

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*John E. Thomas, appointed Chairman July 1, 1993, replacing Julius A. Wright

*Ralph A. Hunt, appointed July 26, 1993, replacing Sarah Lindsay Tate

*Judy Hunt, appointed July 26, 1993, replacing Robert O. Wells

LETTER OF TRANSMITTAL

December 31, 1993

The Governor of North Carolina
Raleigh, North Carolina

Sir:

Pursuant to the provisions of Section 62-17(b) of the General Statutes of North Carolina, providing for the annual publication of the final decisions of the Utilities Commission on and after January 1, 1993, we hereby present for your consideration the report of the Commission's decisions for the 12-month period beginning January 1, 1993, and ending December 31, 1993.

The additional report provided under G.S. 62-17(a), comprising the statistical and analytical report of the Commission, is printed separately from this volume and will be transmitted immediately upon completion of printing.

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION

John E. Thomas, Chairman

William W. Redman, Jr., Commissioner

Charles H. Hughes, Commissioner

Laurence A. Cobb, Commissioner

Allyson K. Duncan, Commissioner

Ralph A. Hunt, Commissioner

Judy Hunt, Commissioner

Geneva S. Thigpen, Chief Clerk

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DOCKET NO. M-100, SUB 123

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Filing of Annual Reports by Municipalities) ORDER REVISING RULE R1-33

BY THE COMMISSION: G.S. 62-47 requires each municipality in North Carolina which furnishes gas, electric, or telephone service to file a verified annual report with the North Carolina Utilities Commission. Commission Rule R1-33 specifies that those annual reports shall be filed not later than October 1 each year based on a fiscal year ended June 30.

On July 12, 1993, the Public Staff filed a motion in this docket whereby the Commission was requested to revise Rule R1-33 to require all municipalities to file their required annual reports not later than November 15 of each year instead of October 1. In support of its motion, the Public Staff stated that it has received a letter from William L. Corbett, Finance Director for the Town of Tarboro, suggesting that the deadline be changed to November 1, since most small municipalities in the State depend on an outside auditor for much of the information requested in the reports and the statutory deadline for submission of the audit is October 31. The Public Staff further stated that requests for one-month extensions are not uncommon and 45 additional days may be needed in some cases.

The Public Staff served a copy of its motion on all municipalities which file annual reports pursuant to G.S. 62-47 and Commission Rule R1-33.

No responses to the Public Staff's motion have been filed.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission finds good cause to amend Rule R1-33 as requested by the Public Staff for the reasons set forth by the Public Staff in its motion of July 12, 1993.

IT IS, THEREFORE, ORDERED that Commission Rule R1-33 be, and the same is hereby, amended by striking the date "October 1st" from the rule and inserting in lieu thereof the date "November 15th." This amendment shall become effective as of the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of August 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. E-100, SUB 64

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina - 1992	)))	ORDER ADDPTING LEAST COST INTEGRATED RESOURCE PLANS

HEARD IN: New Hanover County Courthouse, Wilmington, North Carolina, September 29, 1992; Buncombe County Courthouse, Asheville, North Carolina, September 29, 1992; City Hall, Williamston, North Carolina, September 30, 1992; Charlotte-Mecklenburg Government Center, Charlotte, North Carolina, September 30, 1992; Guilford County Courthouse, Greensboro, North Carolina, October 1, 1992; and Commission Hearing Room, Dobbs Building, Raleigh, North Carolina, November 30 - December 8, 1992.

BEFORE: Commissioner Julius A. Wright, Presiding; Chairman William W. Redman, Jr., and Commissioners Sarah Lindsay Tate, Robert D. Wells, Charles H. Hughes, Laurence A. Cobb, and Allyson K. Duncan

APPEARANCES:

For Carolina Power & Light Company:

Len S. Anthony, Associate General Counsel, Carolina Power & Light Company, Post Office Box 1551, Raleigh, North Carolina 27602

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For North Carolina Power:

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For the Carolina Industrial Group for Fair Utility Rates I and II:

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For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28680

For North Carolina Solar Energy Association and Conservation Council of North Carolina:

John D. Runkle, Post Office Box 3793, Chapel Hill, North Carolina 27515

For Allied Signal:

Nancy Benton Essex, Poyner & Spruill, Post Office Box 10096, Raleigh, North Carolina 27605

For Southern Environmental Law Center:

Oliver A. Pollard, III, and Jeffrey M. Gleason, 201 West Main Street, Suite 14, Charlottesville, Virginia 22902

For Empire Power Company:

R. Palmer Sugg, Broughton, Wilkins, Webb & Jernigan, Post Office Box 2387, Raleigh, North Carolina 27602

For Himself:

Wayne S. Leary, Leary's Consultative Services, 1006 Albemarle Court, New Bern, North Carolina 28562-2502

For the Using and Consuming Public:

William, B. Crumpler, Richard L. Griffin, and Karen E. Long, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For the Using and Consuming Public:

A. W. Turner, Jr. and Gisele L. Rankin, Staff Attorneys, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: The General Statutes of North Carolina require that the Commission analyze the probable growth in the use of electricity and the long-range need for future generating capacity for North Carolina. G.S. 62-110.1 provides, in part, as follows:

"(c) The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Power Commission and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction. In developing such analysis, the Commission shall confer and consult with the public utilities in North Carolina, the Utilities Commission or comparable agencies of neighboring states, the Federal Power Commission, the Southern Growth Policies Board, and other agencies having relevant information and may participate as it deems useful in any joint boards investigating generating plant sites or the probable need for future generating facilities. In addition to such reports as public utilities may be required by statute or rule of the Commission to file with the Commission, any such utility in North Carolina may submit to the Commission its proposals as to the future needs for electricity to serve the people of the State or the area served by such utility, and insofar as practicable, each such utility and the Attorney General may attend or be represented at any formal conference conducted by the Commission in developing a plan for the future requirements of electricity for North Carolina or this region. In the course of making the analysis and developing the plan, the Commission shall conduct one or more public hearings. Each year, the Commission shall submit to the Governor and to the appropriate committees of the General Assembly a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the Commission for the ensuing year in connection with such plan."

Analysis of the long range needs for future electric generating capacity pursuant to G.S. 62-110.1 is included in Rules R8-56 through R8-61 of the Utilities Commission rules as a part of the Least Cost Integrated Resources Planning process. The rules define an overall framework within which the least cost integrated resources planning process will take place in North Carolina.

Least Cost Integrated Resources Planning is intended to identify those electric resource options which can be obtained for the total least cost to the ratepayers consistent with adequate, reliable service. Least Cost Integrated Resources Planning is also a strategy which considers conservation , load management and other demand-side options along with new utility owned generating plants, nonutility generation and other supply-side options in providing cost-effective, high quality electric service.

The General Statutes of North Carolina also require that planning to meet the long-range needs for future generating capacity shall include demand-side options, incentive mechanisms and least cost considerations. G.S. 62-2 provides, in part, that it is declared to be the policy of the State of North Carolina:

"(3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills."

The Commission initiated the initial proceeding to evaluate the Least Cost Integrated Resource Plans (LCIRP) of the regulated electric utilities in December 1988, in Docket No. E-100, Sub 58. On May 17, 1990, following many months of investigation and several weeks of public hearings held throughout the State, the Commission issued an Order Adopting Least Cost Integrated Resource Plans. The Order found that the LCIRPs filed by the electric utilities were at an early stage in their evolution, and that the plans should be recognized as a good faith attempt to achieve an appropriate generation mix at the least cost consistent with reliable service.

On December 31, 1991, the Commission issued an Order in Docket No. E-100, Sub 64, scheduling hearings to analyze and investigate the current LCIRPs to be developed by Carolina Power and Light Company (CP&L), Duke Power Company (Duke), North Carolina Power (NC Power) and Nantahala Power and Light Company (Nantahala) pursuant to the Commission's rules. The Order required the utilities to file their LCIRPs and supporting testimony and exhibits in conformity with Commission Rules R8-56 through R8-61 by April 3, 1992. The Commission also ordered the Public Staff and other intervenors to file their reports, comments, testimony and exhibits by September 4, 1992. Persons desiring to intervene in the proceeding as formal parties of record were required to petition the Commission by September 4, 1992, and to file any expert testimony and exhibits by that date. The December 31, 1991, Order scheduled the proceeding for public hearing in Raleigh beginning on October 6, 1992, and also established a series of public hearings to be held in Asheville, Charlotte, Greensboro, Wilmington, Williamston, and Raleigh for the purpose of taking non-expert public witness testimony.

The following parties requested and were allowed to intervene and participate in the proceeding: Empire Power Company (Empire); the Public Works Commission of the City of Fayetteville; the Carolina Utility Customers Association, Inc. (CUCA); the Southern Environmental Law Center (SELC); the Carolina Industrial Groups for Fair Utility Rates I and II (CIGFUR); the North Carolina Solar Energy Association (NCSEA); the Conservation Council of North Carolina (CCNC); Allied Signal, Inc.; LG&E Development Corporation (LG&E); and Wayne Leary. The Attorney General also filed its Notice of Intervention.

On July 22, 1992, Saluda River Electric Cooperative (SREC) petitioned the Commission to intervene in the LCIRP proceeding. In August 1992, Duke and the Public Staff filed responses to the SREC petition, and SREC filed a response to the Duke Response. On August 19, 1992, the Commission issued its Order Denying Petition To Intervene, noting that SREC has no customers in North Carolina and has shown no real interest in the LCIRP proceeding in North Carolina.

On January 14, 1992, the Commission issued its Notice to Parties. This Notice indicated that the matter would be heard by the full Commission and that Commissioner Julius A. Wright had been requested to serve on the Project Advisory Committee for a limited study considering the economics of utility demand-side management (DSM) programs for low-income customers to be jointly conducted by the states of New York and North Carolina. Any party to the proceeding who wished to object to Commission Wright's participation in both the study and this proceeding was ordered to file a formal objection within ten days of the Notice. No objections were filed.

On January 17, 1992, CP&L filed its Motion to Revise Filing Dates. The Motion requested that the utilities be allowed until April 24, 1992, to file their LCIRPs. CP&L's Motion also requested the Commission to change the filing date for intervenor testimony and exhibits to August 21, 1992. On January 24, 1992, the Public Staff filed its Response to CP&L's Motion to Revise Filing Dates in which it opposed the motion to extend time.

On January 29, 1992, the Commission issued its Order Revising Filing dates and Rescheduling Hearings. Pursuant to the Order, the utilities were given until April 24, 1992, to file their LCIRPs. Persons desiring to intervene in this proceeding were required to petition the Commission by September 25, 1992, and the Public Staff and other intervenors were ordered to file their reports, comments, testimony and exhibits by that same date. A hearing for the taking of non-expert public witness testimony was scheduled for November 30, 1992, and a hearing for the taking of expert testimony was set for December 1, 1992. The January 29 Order also revised the publication deadlines applicable to the utilities in this proceeding.

On January 24, 1992, the Public Staff filed its Motion to Include the North Carolina Electric Membership Corporation (NCEMC) in the Least Cost Proceeding. The Public Staff's Motion was denied by Order of the Commission dated March 3, 1992. The Order cited the Commission's belief that it would be both appropriate and fair to adopt a rule governing NCEMC participation in LCIRP proceedings before requiring such NCEMC participation. A rulemaking proceeding to define the scope of NCEMC participation in LCIRP proceedings was initiated by separate Order in a new docket.

LCIRPs were filed by CP&L, Duke, NC Power and Nantahala in April 1992 pursuant to the Commission's Order of January 29, 1992.

On April 28, 1992, the Commission issued its Order Requiring Status Reports. The Order required the utilities and the Public Staff to file reports describing the status of the negotiations between the utilities and the Public Staff regarding the proposals filed by the respective utilities for recovery of DSM costs and for incentives for positive LCIRP accomplishments. The utilities had filed their proposals in response to the Commission's requirements in the previous LCIRP proceeding in Docket No. E-100, Sub 58. The Commission ordered these parties to submit their status reports in Docket No. E-100, Sub 64, by May 31, 1992.

The Public Staff, CP&L, Duke, NC Power and Nantahala submitted their status reports regarding DSM cost recovery proposals as required by the Commission's Order of April 28, 1992.

On June 24, 1992, Empire filed its Motion to Include Costs, Revenues and Plans for Clean Air Act Compliance in the LCIRP proceedings. The Public Staff, Duke, NC Power and CP&L each submitted a response to the June 24, 1992 motion in July 1992. The Commission issued Order Denying Motion To Include Clean Air Act Compliance on August 19, 1992, in which it denied Empire's motion.

Empire filed a Motion to Further Define Commission Rule R8-58(e) and the Evaluation Process for Non-Utility Generation Proposals on June 30, 1992. The Public Staff, CP&L, Duke and NC Power each submitted a response to the June 30, 1992, motion in July 1992. On August 19, 1992, the Commission issued a separate Order Requiring Prefiled Testimony in which it required all parties of record to prefile testimony within 30 days addressing the issues of: (1) the interpretation and/or clarification of Commission Rule R8-58(e) and (2) the need for and/or the terms of an appropriate evaluation process by which utilities should assess future non-utility purchased power proposals. Interested parties were provided 60 days to prefile testimony addressing the testimony of other parties on these issues.

Direct testimony was submitted pursuant to the Commission's August 19, 1992 Order regarding Rule R8-58(e) by Empire, NC Power, Duke, CP&L, Nantahala and the Public Staff in September 1992.

On August 19, 1992, the Commission issued a separate Order Requiring Prefiled Testimony in which the utilities were required to prefile testimony within 30 days addressing those issues regarding DSM cost recovery and incentive mechanisms which remained unresolved between the respective utilities and the Public Staff. The Order provided that the prefiled testimony must include a discussion of those areas where the parties were in agreement, and also reference any earlier prefiled testimony which already addressed the relevant issues. The Order required the Public Staff and intervenors to prefile testimony within 60 days of the Order's issuance.

On September 10, 1992, Duke and NC Power each requested that it be granted until October 18 or 19, 1992, to reduce its agreement with the Public Staff regarding DSM cost recovery and incentive mechanisms to writing in the form of a stipulation and/or file testimony of its expert witnesses. The Commission issued an Order Granting Extension of Time on September 15, 1992, in which Duke and NC Power were allowed an extension of time until October 18, 1992, within which to file either testimony or stipulations addressing DSM cost recovery and incentive mechanisms. The Public Staff and the intervenors were allowed thirty days after October 18 to file testimony addressing the filings of Duke and NC Power. The Order left unchanged the applicable filing deadlines for CP&L and Nantahala. CP&L filed a Motion for Extension of Time In Which to Prefile Testimony Regarding DSM Cost Recovery And Incentive Mechanisms on September 18, 1992. Pursuant to the Commission's September 22, 1992, Order Granting Extension of Time, CP&L was given until October 18, 1992, to file either testimony or stipulations addressing DSM cost recovery and incentive mechanisms. The Public Staff was allowed 30 days after October 18 to file testimony addressing the CP&L filing.

On September 24, 1992, SELC and CIGFUR requested that they be given until September 30, 1992, to file their prefiled testimony. The Motions of SELC and CIGFUR were granted by the Commission's September 28, 1992, Order Granting Extensions of Time.

On September 24, 1992, the Public Staff filed a Motion for Extension of Time to File Testimony until November 10, 1992. The reason the Public Staff requested the extension was to allow it time to conclude certain negotiations with the utilities regarding the LCIRP process prior to the filing of testimony. This Motion was granted by the Commission's September 28, 1992, Order Granting Extension of Time.

On September 29, 1992, CIGFUR filed a similar motion for an extension of time to file testimony until November 10, 1992, which also indicated that CIGFUR wished to participate in the negotiations between the utilities and the Public Staff. The Public Staff, Duke, CP&L, and NC Power filed responses to CIGFUR's Motion on October 5, 6 and 8, 1992. The Commission granted CIGFUR's Motion for an Extension of Time by Order dated October 9, 1992. However, in this Order the Commission explicitly stated that the Order did not require collective negotiations. The Order did require that any stipulations entered into between the Public Staff and the utilities be promptly filed with the Commission.

On October 19, 1992, the Public Staff made an oral Motion on behalf of Duke and NC Power for a one-day extension of time to file testimony regarding DSM cost recovery and incentive mechanisms. On that same date, CP&L filed a Motion which requested that it be given until October 30, 1992, to file testimony with respect to DSM cost recovery and incentive mechanisms. The Commission granted both of these Motions in its October 19, 1992, Order Granting Extension of Time.

On October 20, 21 and 30, 1992, stipulations with the Public Staff regarding DSM cost recovery and incentive mechanisms as well as supporting supplemental direct testimony were filed by NC Power, Duke and CP&L respectively.

On November 10, 1992, the Public Staff filed the direct testimony of W. Michael Warwick and Thomas Foley as well as a report entitled "Least - Cost Integrated Planning in North Carolina: Review, Interpretations, and Recommendations". The filing included individual Joint Stipulations by the Public Staff with NC Power, Duke and CP&L respectively. Direct testimony and exhibits were also filed by CIGFUR on November 10, 1992.

By letter dated November 12, 1992, Duke notified the Commission that Donald H. Denton would adopt the previously-filed testimony of F. Alfred Jenkins, and that James R. Hendricks would adopt the previously-filed testimony of Richard B. Priory. The letter also indicated that Duke intended to present Donald H. Denton, William F. Reinke, James R. Hendricks, and Candace A. Paton as a panel at the December 1, 1992, hearing.

The Commission issued its Prehearing Order on November 13, 1992. On November 18, 1992, CIGFUR submitted the supplemental testimony of Nicholas Phillips, Jr.

On November 18, 1992, the Public Staff filed a Motion for Change in Response Due Dates. The Motion requested the Commission to permit the Public Staff until November 23, 1992, to file its testimony in response to the testimony of NC Power and CP&L. The Public Staff's Motion was granted by the Commission's November 20, 1992, Order Granting Motion for Change in Response Due Dates.

On November 19, 1992, SELC filed the testimony of Paul Chernick regarding DSM cost recovery and incentive mechanisms. The Public Staff filed the Affidavit of Michael C. Maness on November 23, 1992, and on November 25, 1992, the Public Staff filed revised testimony of its expert witnesses. CP&L filed the rebuttal testimony of Dr. John L. Harris and B. Mitchell Williams on November 30, 1992. Wayne S. Leary filed his supplemental direct testimony and NC Power submitted the rebuttal testimony of Mary C. Doswell on December 1, 1992. On December 2, 1992, Duke filed the rebuttal testimony of Donald H. Denton, Jr.

The matter came on for hearing on December 1, 1992, as previously noticed and scheduled.

The testimony of N. Edward Tucker, Jr., Executive Vice President of Nantahala was stipulated into the record.

CP&L presented the testimony and exhibits of the following witnesses as a panel: Bobby L. Montague, Vice President, System Planning and Operations; David R. Nevil, Manager, Rates and Energy Services Department; B. Mitchell Williams, Manager, Demand Side Management Programs; Dr. John L. Harris, Manager of Forecasting and Revenue Requirements; and Verne B. Ingersoll, II, Manager of System Planning.

Duke presented the testimony and exhibits of the following witnesses as a panel: Donald H. Denton, Jr., Senior Vice President, Planning and Operating; William F. Reinke, Vice President of System Planning and Operating; James R. Hendricks, Manager of Environmental Protection, Generating Services Department; and Candace A. Paton, Manager, Regulatory Accounting.

NC Power presented the testimony and exhibits of the following witnesses as a panel: Thomas J. O'Neil, Vice President of Energy Efficiency; Dr. Samuel M. Laposata, Chief Economist; Mary C. Doswell, Manager of Demand Side Planning; Glenn B. Ross, Manager of Planning; and Ripley C. Newcomb, Director of Demand Side Analysis.

The Public Staff presented the testimony of a panel consisting of Thomas J. Foley and W. Michael Warwick of the Battelle Northwest Laboratories. This panel sponsored a report entitled "Least-Cost Integrated Resource Planning in North Carolina: Review, Interpretations, and Recommendations." The Public Staff also presented the testimony of Michael C. Maness, Supervisor of the Electric Section of the Accounting Division of the Public Staff. Mr. Maness testified regarding unresolved issues associated with the DSM cost recovery and bonus mechanisms of CP&L and North Carolina Power. Finally, the Public Staff presented the testimony of Kerim Lamar Powell, an engineer with the Electric Division of the Public Staff, who testified regarding the evaluation of non-utility generator (NUG) purchased power proposals.

Empire presented the testimony of Steven L. Greenberg, Vice President of Empire, who testified with respect to utility assessments of NUG proposals and the specific LCIRPs of Duke and CP&L.

Allied-Signal, Inc., presented the testimony of Frederick R. Plett, a Regulatory Affairs Specialist with Allied-Signal, who testified regarding the use of amorphous metal in electric utility transformers.

Leary's Consultative Services presented the testimony of Wayne S. Leary, principal consultant for Leary's Consultative Services and President of Peat

Energy, Inc. who testified with regard to utility evaluations of NUG purchased power proposals. Mr. Leary's presentation included a resolution and supplemental testimony which was stipulated into the record. Certain deletions were made to this testimony based on objections raised during the hearing.

The SELC presented the testimony of Paul L. Chernick, President of Resource Insight, Inc., whose testimony was stipulated into the record. Mr. Chernick testified regarding the LCIRPs as well as the DSM cost recovery and incentive mechanisms of Duke, CP&L and NC Power. Certain deletions were made to this testimony based on a stipulation reached between Duke and SELC.

CIGFUR presented the testimony of Nicholas Phillips, Jr., of Drazen-Brubaker and Associates, Inc., who testified with respect to the LCIRPs filed by Duke, CP&L and NC Power, certain associated ratemaking issues and the stipulations regarding DSM cost recovery and bonus mechanisms.

The rebuttal testimony of various utility witnesses were also stipulated into the record. CP&L presented the rebuttal testimony of Dr. John L. Harris, who testified regarding the use of economic principles relied upon by SELC witness Chernick. CP&L also presented the rebuttal testimony of B. Mitchell Williams in response to witness Chernick's criticisms of CP&L's DSM programs and strategy. Duke presented the rebuttal testimony of Donald H. Denton, Jr., in response to the testimony of SELC witness Chernick. NC Power presented the rebuttal testimony of Mary C. Doswell, who testified in response to SELC witness Chernick. NC Power also submitted the rebuttal testimony of Jeffrey L. Jones, Director of Capacity contracts, who testified in response to the NUG evaluation proposals of Empire witness Greenberg and Public Staff witness Powell.

Public witnesses who testified in this proceeding were as follows:

Asheville - Marjorie Lockwood

Charlotte - No witnesses

Greensboro - No witnesses

Wilmington - No witnesses

Williamston - No witnesses

Raleigh - Martha Drake, Jane Sharp and Sarah Ladd.

In addition to the foregoing, there were other motions, filings and Orders not specifically mentioned, which are a matter of public record. Based on the information contained in the utilities' filings, the testimony and exhibits introduced at the hearings, and the Commission's record of this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. CP&L, Duke, NC Power and Nantahala are duly organized as public utilities operating under the laws of the State of North Carolina and are subject to the jurisdiction of the North Carolina Utilities Commission. The utilities are engaged in the business of developing, generating, transmitting,

distributing, and selling power to the public throughout the State of North Carolina. CP&L has its principal offices and place of business in Raleigh, North Carolina. Duke has its principal offices and place of business in Charlotte, North Carolina. NC Power has its principal offices and place of business in Richmond, Virginia. Nantahala has its principal offices and place of business in Franklin, North Carolina.

2. The two largest electric utilities in North Carolina are Duke and CP&L, which together generate approximately 95% of the electricity consumed in the State. Virginia Electric and Power Company generates most of the remaining 5%. Approximately two thirds of the utility business of both Duke and CP&L is located in North Carolina, with the remainder located in South Carolina. On the other hand, the major portion of the utility business of Virginia Electric and Power Company is located in Virginia, while less than 5% of its utility business is located in North Carolina. Virginia Electric and Power Company operates in North Carolina as NC Power.

Nantahala Power and Light Company is the fourth largest electric utility in North Carolina and generates some of its own energy requirements utilizing hydroelectric facilities. Nantahala is a wholly-owned subsidiary of Duke. There are several smaller electric utilities regulated by the Utilities Commission, but none of them generate their own energy requirements.

The North Carolina Utilities Commission does not regulate the rates and service practices of municipally owned electric utilities or electric membership cooperatives. However, the Commission does have jurisdiction over licensing of new electric generating plants operated by municipalities or electric cooperatives. The Commission is currently conducting a rulemaking proceeding to consider appropriate participation by North Carolina Electric Membership Cooperatives (NCEMC) in the Least Cost Integrated Resource Planning process. NCEMC acquires electric generating capacity for its participating membership cooperatives primarily by means of wholesale purchases from the regulated electric utilities, but it now seeks to supply some of that capacity from its own generating facilities.

3. The Public Staff entered into individual stipulations with CP&L, Duke and NC Power prior to the public hearings regarding on-going development of the LCIRP process. By entering into those stipulations, each utility agreed to the objectives of the Public Staff's recommendations in this docket and agreed to meet those objectives through certain specified actions. The stipulations all contain the following agreement: "As is current practice, [the Company] will not eliminate any DSM option during the screening stage based on the RIM test results." The stipulations are in the best interests of all the parties to this proceeding and the general public and should be approved.

4. The compound annual growth rates currently forecast by CP&L for 1992 to 2006 are:

Summer Peak	-	1.7%
Winter Peak	-	1.7%
Energy	-	1.8%

5. The compound annual growth rates currently forecast by Duke for 1992 to 2006 (from July 1992 update forecast) are:

Summer Peak	-	2.3%
Winter Peak	-	2.5%
Energy	-	2.0%

6. The compound annual growth rates currently forecast by NC Power for 1992 to 2006 are:

Summer Peak	-	2.6%
Winter Peak	-	2.8%
Energy	-	2.8%

7. The compound annual growth rates currently forecast by Nantahala for 1992 to 2006 are:

Summer Peak	-	2.4%
Winter Peak	-	2.3%
Energy	-	2.9%.

8. The LCIRPs filed by CP&L, Duke and NC Power, viewed in conjunction with the individual stipulations entered into between the utilities and the Public Staff, indicate a mutual understanding of the purpose of integrated resource planning and provide the steps necessary to enhance future DSM activities. The Commission recognizes that LCIRP is an evolving, dynamic process, and that new information and new understandings on planning principles will continue to be developed in the future. The LCIRPs filed herein, combined with the stipulations between the utilities and the Public Staff, comply with the Commission's LCIRP rules while recognizing the need to continue utility efforts to enhance their LCIRP processes.

Duke's LCRIP includes significant DSM program targets. The Commission commends Duke's emphasis on DSM programs and its aggressive pursuit of pilot programs

For purposes of this proceeding, the LCIRPs of CP&L, Duke, NC Power and Nantahala should be approved.

9. The Public Staff entered into individual stipulations with CP&L, Duke and NC Power prior to the public hearings in which NC Power and CP&L established DSM cost deferral mechanisms and all three utilities established incentive mechanisms that provide an opportunity to earn rewards for demonstrated DSM accomplishments. The stipulations are in the best interests of all the parties to this proceeding and the general public and should be approved.

10. Each utility's evaluation of the cost-effectiveness of DSM programs should be based on a 19-year planning horizon excluding "end-effects." Calculation of a reward pursuant to the stipulation with Duke regarding DSM cost recovery and incentive mechanisms will result in a fair and reasonable reward level.

11. A cost recovery/incentive mechanism for supply-side costs or transmission/distribution efficiency investments, either in the form of an annual rider or a deferral accounting mechanism, should not be approved herein.

12. It is reasonable and appropriate for the Commission to establish certain guidelines for utility evaluations of purchased power proposals by NUGs after allowing interested parties an opportunity to file comments on the proposed guidelines.

13. It would not be appropriate for the Commission should not attempt to revise or clarify Rule R8-58(e) until such time as the issue of guidelines for evaluation of purchased power proposals has been fully addressed.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. I AND 2

These findings are essentially informational and jurisdictional in nature and are not in controversy.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

In response to the Commission's December 31, 1991, and January 29, 1992, Orders in this docket, each utility filed its LCIRP, testimony and exhibits in conformity with the provisions of Commission Rules R8-56 through R8-61.

The Public Staff retained consultants W. Michael Warwick and Thomas J. Foley of Battelle Pacific Northwest Laboratories to review the LCIRPs, the resource planning processes underway within the three largest North Carolina investor-owned utilities (CP&L, Duke and NC Power) and the progress made from the stipulations reached by the utilities and the Public Staff in the initial least cost proceeding. The Public Staff's consultants prepared a report entitled "Least-Cost Integrated Resource Planning in North Carolina: Review, Interpretations, and Recommendations," dated November 10, 1992. This report was organized into four chapters: (1) Introduction; (2) Next Steps in Least-Cost Integrated Resource Planning; (3) Stipulation Review; and (4) Conclusions and Recommendations.

The consultants concluded that the North Carolina utilities continue their progress in resource planning and the adoption of LCIRP methods. However, the consultants also addressed several areas, especially those associated with comprehensive treatment of energy efficiency and load management programs and their integration into utility plans, that need improvement. Accordingly, the consultants offered specific guidance to improve planning processes for the utilities' next LCIRPs so that the filings more closely conform to LCIRP principles as envisioned by the consultants. Further, a number of other intervenors were critical of specific aspects of the utilities' LCIRPs, as discussed hereafter.

The Public Staff entered into individual stipulations with CP&L, Duke and NC Power prior to the hearing. The stipulations were developed through extensive discussions between the Public Staff, the consultants and the individual utilities. In summary, the utilities agreed to a number of the objectives of the Public Staff's recommendations and acknowledged that they have complied or will comply with the objectives of the recommendations by certain actions enumerated in the stipulations. The parties also acknowledged that compliance with those objectives may require continued collaboration with the Public Staff. Although certain intervenors expressed concern about particular points addressed in the stipulations, the stipulations address those concerns to the satisfaction of the Commission.

The stipulations were the result of significant and intense discussions between the parties. The Commission is confident that the stipulations represent ample assurance that the resources necessary to meet future growth will include appropriate reliance upon the entire spectrum of demand side options, including conservation, load management and energy efficiency programs as additional resources to meet future energy needs. The Commission is particularly persuaded by the testimony of Public Staff witnesses Warwick and Foley, who assured the Commission that the satisfaction of the objectives reflected in the stipulations will reflect continued improvement in the utilities' DSM efforts and compliance with the Commission's LCIRP rules.

The conclusions and recommendations of the Public Staff report served as the basis of the collaborative effort between the Public Staff and the individual utilities in resolving the issues raised by the Public Staff's consultants in this proceeding. These stipulations were submitted to the Commission by the affected parties with the understanding that the stipulations settled all issues in controversy between the Public Staff and the utilities with regard to each utility's LCIRP unless specifically noted. The stipulations were the result of numerous meetings and extensive work by all parties involved. Compromises were accepted by each party with respect to positions they might have otherwise taken absent these stipulations.

Although numerous questions were asked and issues raised by the parties to this proceeding with respect to a number of the stipulations, the following stipulations are representative of the issues addressed and will be discussed in greater detail:

Recommendations A-1 - "Adopt end-use forecasting models for energy and peak forecasting." The utilities and the Public Staff agreed that the objective of the recommendation is to take advantage of both end-use and econometric forecasting techniques in meeting the needs of the integrated resource planning (IRP) process with the intent of incorporating end-use techniques in the utilities' next IRP filings. The Public Staff panel indicated that the end-use approach allows the forecast to include the effects of structural changes that specifically affect energy use, such as new building codes, changes in the type and size of houses, more efficient appliances, changes in hndustrial processes, and other significant structural changes. The panel also acknowledged that end-use methods are compatible with economic methods. However, the end use methods have not yet proven to be more accurate or reliable in projecting future energy trends than other forecasting models.

Recommendation B-1 - "Implement the supply curve approach for DSM." The utilities and the Public Staff agreed that the objective of the recommendation is to conduct a comprehensive assessment of DSM potential and to clearly communicate the results in a format having a common basis for all DSM options. The consultants recommend the use of screening curves in the manner applied to supply side options. The utilities have agreed to review and enhance their DSM assessments and modelling techniques to achieve the same objective as the supply curve example cited in the Public Staff report. Those efforts will include better documentation of the results of DSM assessments, including a simplified graphic or spreadsheet presentation of DSM costs for comparative purposes. However, as acknowledged by the Public Staff panel, the supply curve methodology is a "means to an end" and not an end in itself.

Recommendation C-1 - "Incorporate DSM supply curves and multiple forecasts into resource integration approach." The utilities and the Public Staff agreed that the objective of the recommendation is to use a planning process that competitively selects supply and demand resources in a manner that recognizes the risks inherent in a broad range of reasonable alternative forecasts. This stipulation must also be viewed in light of Recommendations C-1, 2 and 3, which reflect the broad range and nature of uncertainties to be examined in the future.

Recommendation D-3 - "Initiate aggressive programs to improve energy efficiency among new customers." The utilities and the Public Staff agreed that the objective of the recommendation is to initiate programs that improve the energy efficiency of new customers. The new customer market is a prime area for DSM programs because these programs may provide immediate benefits to hold down peak growth and ultimately forestall new base load plants, to the benefit of all customers.

Recommendation E-1 - "Increase level of detail in STAPs and include programs and issues as well as accomplishments." The utilities and the Public Staff agreed that the objective of the recommendation is to expand the short term action plans (STAP) to provide greater detail. The STAPs should include additional details regarding problems identified, resolved or avoided. Furthermore, the Company's progress in achieving the objectives of the stipulations should likewise be reflected in the STAPs. Accordingly, the "Progress Reports" that were required by the Commission following the May 1990 Order would result in a duplication of the STAP filing requirements and should no longer be required.

SELC recommended that the stipulations between the Public Staff and CP&L and Duke respectively should be approved. SELC also recommended that stipulations between the Public Staff and NC Power should be approved except for the portion of Recommendation D-3 in which NC Power notes its use of the Rate Impact Measure (RIM) test for DSM evaluations and acknowledges that the Public Staff may press for a change in the Company's use of the RIM test in the future.

Public Staff witnesses Foley and Warwick, SELC witness Chernick, CP&L witnesses Nevil and Williams and Harris, Duke witness Denton, NC Power witness Doswell, and CIGFUR witness Phillips discussed various cost tests for DSM programs. SELC opposes the use of the RIM test by any utility. CIGFUR supports the use of the RIM test at all stages of evaluation. Both CIGFUR and CUCA contend that the RIM test is the most useful one to indicate whether or not a DSM program is likely to require a subsidy by nonparticipants. CUCA contends that large industrial customers are already subsidizing other customer classes and urges the Commission to avoid DSM programs that become devices for industrial customers further subsidizing other customers. Public Staff witnesses Foley and Warwick and Duke witness Denton testified that the cost tests are being overemphasized. Denton indicated that screening DSM programs on the basis of the RIM test will give a company a wrong answer. The Commission agrees. The Commission notes general agreement that the results of the RIM test should be considered before a DSM program is adopted; however, the Commission concludes that use of the RIM test at the assessment stage is inappropriate because it can exclude consideration of many programs that might otherwise be adopted as part of a total DSM package. The Commission notes that the stipulations adopted in the last least cost proceeding forbade use of the RIM test to screen out DSM programs at the assessment stage. The new stipulations by CP&L, Duke and NC Power all contain the following agreement: "As is current practice, [the Company] will not eliminate any DSM option during the screening stage based on the RIM test results." Because the cost tests were discussed so extensively during the hearing, the Commission concludes that the provisions of the stipulations prohibiting use of the RIM test for screening DSM programs should be reaffirmed.

The Commission concludes that the stipulations are in the best interest of the parties to this proceeding as a whole and that they should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 THROUGH 7

Pursuant to G.S. 62-110.1, the Commission must keep current an analysis of the long-range needs for future generation facilities in North Carolina. CP&L, Duke, and NC Power filed their load forecasts as part of their LCIRP plans in this proceeding.

Since the last LCIRP proceeding, the companies have improved their forecasting techniques according to the Public Staff. Specifically, more end-use models and the local data needed to run them are being used. The Public Staff, however, was critical of the forecasting techniques and processes used by the companies, but not to the degree that it was in the last LCIRP proceeding. The Public Staff's criticisms in this proceeding were that (1) the companies still rely too heavily on econometric models and (2) the forecasts do not adequately consider a broad range of uncertainties.

Public Staff witnesses Warwick and Foley testified that the result of the companies' continuing to rely primarily on econometric models for their forecasts could be "cumulative errors that seriously affect the forecast." They were also critical of the technique of point forecasts; i.e., reliance on a single or limited number of precise forecasts. They instead urged the companies to implement a range of forecasts that could cover a wide range of possible futures, for which flexible plans could be adopted.

Witnesses Warwick and Foley were unable to state whether the forecasts presented by the companies were too high, too low, or reasonably accurate. They concluded that the combination of reliance on (1) econometric techniques and (2) one or a limited number of forecasts caused concern. Witness Warwick testified that "It's the unknowness that bothers us."

The Public Staff also pointed out that the companies have agreed to revise their forecasting techniques to address its two major concerns. Witnesses Foley and Warwick concluded that, "Compliance with the proposed stipulations will ultimately result in a plan suitable for both near and long-term source decisions."

For purposes of meeting its obligation under G.S. 62-110.1, the Public Staff concluded that the companies' forecasts are reasonable estimates of average annual peak load and energy growth rates over the 15-year period of 1992 to 2006 and are appropriate to use for planning purposes at this time.

CP&L witness Harris testified as to the process CP&L used in developing its energy and load forecasts and the role such forecasts play in the development of CP&L's LCIRP. Witness Harris testified that CP&L's forecasts take account of the effect of projected demographic, economic, technological and meteorological factors on electricity use. CP&L uses independent econometric and end-use methods to make its projections. Econometric methods focus on actual market behavior over long periods of time. End-use methods utilize detailed information concerning customer choices on appliances and their operating characteristics. Using both methods allows CP&L to benefit from the strengths of each method and provides CP&L a means of forecast verification.

CP&L witness Montague testified that CP&L is facing a highly uncertain economic, regulatory and technological future. He explained that CP&L's forecasting methods attempt to take such uncertainties into account. For example, CP&L develops high and low growth scenario forecasts in addition to a reference forecast. In addition, CP&L utilizes decision analysis techniques to assess the impact of forecast uncertainty on the LCIRP. These techniques help minimize the uncertainties inherent in long-range forecasting, and enable CP&L to develop an LCIRP that is consistent with the goals of maintaining adequate and reliable supplies of electricity and maintaining system flexibility.

Witness Harris testified that, based on its energy and load forecasts, CP&L expects its energy growth to average 1.8% annually and its load growth to average 1.7% annually over the next 15 years. Growth rates are expected to average about 3% in the early years of that 15-year period and average 1.3% in the later years. He explained that the relatively slow growth reflected in CP&L's forecasts is due to a number of factors, including: CP&L will lose the City of Camden as a customer effective May 1, 1995; potential load losses due to CP&L's changing wholesale market relationships and the availability of power on the wholesale market; the prospect of increasing appliance efficiency; stricter building codes; and possible increased use of natural gas by customers in CP&L's service area.

The following table illustrates the general range of average annual growth possibilities for energy and peak load from 1992 to 2006 as projected by CP&L.

	Energy	Peak Load
Slower Growth Scenario:	1.8%	1.7%
Reference Forecast:	2.1%	2.1%
Higher Growth Scenario:	2.5%	2.5%

Duke witness Denton adopted the prefiled testimony of F. Alfred Jenkins and testified that the peak and energy forecast for Duke's service area is the starting point for the LCIRP process. He explained that Duke's forecasting process incorporates a variety of statistical and econometric methods and techniques to describe and forecast the relationship between electric demand and energy requirements and various economic, demographic and environmental factors. Duke's peak demands and energy requirements track service area economic conditions very closely. The results of the service area economic models are projections for the three key indicators of economic health of the service area. These are real (inflation-adjusted) gross regional product (GRP), real total disposable personal income, and employment. These projections serve as critical inputs to the modeling process for system peak demand and energy requirements.

Witness Denton testified that Duke's LCIRP is based on forecasted compound annual growth rates for summer and winter peak loads of 2.4% or an average of 408 MW per year, and 2.7% or an average of 434 MW per year, respectively. The summer peak is expected to remain dominant through the forecast horizon. Consistent with the forecasts for peak demand, energy requirements are expected to increase 2.4% per year. The fastest growing sector continues to be general service at 3.2%, followed by industrial at 2.1%, and residential at 1.8%.

Witness Denton also testified that Duke adopted a new long term forecast for the period 1992 through 2006 on May 26, 1992, and that the Company had not yet prepared a revised LCIRP based on the new load forecast. The new forecast projects compound annual growth rates for summer peak loads at 2.3%, for winter peak loads at 2.5% and for energy sales at 2.0% for the period.

NC Power witness Laposata described the models and assumptions used to calculate the Company's forecast of energy and peak demand and presented the Company's current forecast for the period 1992 through 2011. Witness Laposata pointed out that the forecasts are based on the assumption of moderate interest rates and inflation rates throughout the planning period. He also addressed a number of forecasting enhancements since the last LCIRP investigation. His forecast of compound annual growth rates for the period 1992 through 2011 is as follows:

	Unadjusted	Adjusted for DSM
Summer Peak:	2.6%	2.5%
Winter Peak:	2.5%	2.1%
Energy Output:	2.5%	2.5%

His forecast for the period 1992 to 2006 is 2.6%, 2.8% and 2.8% growth rates for summer peak, winter peak and energy respectively.

Nantahala witness Tucker presented testimony on Nantahala's forecast of peak and energy for the period 1992 through 2006. The compound annual growth rate is expected to be as follows:

Summer Peak:	2.4%
Winter Peak:	2.3%
Energy:	2.9%

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

Extensive testimony and exhibits were presented in this proceeding regarding the LCIRP filed by each utility. The following is a summary and discussion of the testimony and information available to the Commission.

Carolina Power & Light Company

CP&L witness Montague described the overall objective of CP&L's integrated resource planning as "the development of a flexible resource plan which will provide an adequate and reliable supply of electric power to our customers at the lowest reasonable cost." Witness Montague added that "CP&L's IRP achieves this objective by incorporating a cost-effective mix of demand-side and supply-side resources which will increase the utilization of existing resources and will minimize the price of electricity."

In developing its LCIRP, CP&L concluded that due to its present capacity resources it was not appropriate to engage in any additional full-scale conservation programs. Rather, CP&L concluded that it should focus its efforts on load shifting, peak clipping and valley filling DSM programs which better address CP&L's system need for peaking resources. CP&L witness Montague testified that valley filling DSM programs assist in the better utilization and increased efficiency of existing capacity, while peak clipping DSM will defer the need for peaking capacity. Given CP&L's current and forecasted needs, these are the two objectives CP&L intends to focus upon during the planning period. Full scale implementation of additional conservation programs is not currently needed and will be timed to meet the projected need for base load capacity.

SELC witness Chernick testified that CP&L's strategy was inconsistent with the LCIRP objective of minimizing total costs. Witness Chernick's position was based on the view that additional aggressive conservation programs might allow CP&L to defer future capacity needs and that failure to institute such programs would lead to lost opportunities that could not be recaptured.

CP&L witness Nevil testified that CP&L's LCIRP indicates only the need for combustion turbines from the mid-1990s until well after the turn of the century. CP&L's existing base load capacity is adequate throughout the planning period. Further, the existing base load generating units have the potential to supply significantly more energy than they currently are required to produce to meet customer needs. CP&L's annual fossil steam capacity factors are projected to be less than 60 percent through 1999. These units are believed to be capable of reliably operating above the 70 percent level, which indicates that their energy production capability will not be fully utilized. Improving the utilization of the existing facilities will improve their operating efficiency. As a result, there is currently no immediate need for additional conservation programs. Rather, load shifting and peak clipping DSM programs aimed at deferring the need for future peaking capacity are the most appropriate programs at this time. Thus, strategic sales programs, that is, programs targeted at valley filling and strategic load growth, coupled with programs aimed at the other load shape objectives, will help improve the utilization of existing facilities and defer the need for future rate increases.

Public Staff witness Warwick noted that each utility involved in this LCIRP proceeding finds itself in different circumstances with regard to meeting future demands for the supply of electricity. When asked whether each utility should be allowed to pursue customized programs for meeting their demand, witness Warwick expressed definite support for the proposition. Witness Warwick also stated that each utility should implement DSM programs that are consistent with their capacity requirements.

CP&L Witness Williams rebutted witness Chernick's conclusion that CP&L was not making appropriate efforts to pursue conservation. Witness Williams noted that CP&L began implementing conservation programs in the 1970s, and that nine of the 19 DSM programs CP&L is currently conducting or actively pursuing have conservation as a primary or secondary objective. Furthermore, CP&L is actively engaged in evaluation and enhancement of its conservation programs.

CP&L currently uses four economic tests to evaluate the economic costs and benefits of DSM programs. These tests are (1) the Utility Cost test, (2) the Rate Impact Measure (RIM) test, (3) the Participant test, and (4) the Total Resource Cost (TRC) test. Each of these tests measures the potential net cost or net benefit of a DSM program by considering supply costs, utility program costs, participant costs, changes in utility revenues, changes in bills to participants, incentives paid to participants, and participation charges paid to the utility.

Each test, however, measures potential costs and benefits from a different perspective. The Utility Cost test measures cost-effectiveness from the standpoint of the utility's total costs. The RIM test assesses cost-effectiveness from the perspective of all ratepayers' total costs. The Participant test focuses on the costs and benefits to a customer that elects to participate in the DSM program. The TRC test measures the cost-effectiveness of a program from the perspective of the utility and all ratepayers as a whole.

CP&L witness Williams explained that CP&L utilizes all four of these tests, and that the results of CP&L's economic evaluations are expressed in terms of Net Present Value (NPV). Tests resulting in positive NPVs mean that the benefits over time outweigh the costs of the program over time. CP&L uses NPV as an indicator of long-term economic feasibility but also considers a number of other criteria in selecting DSM options for its LCIRP. Other factors taken into account include market potential, technical feasibility, impact on operations and reliability, environmental issues and regulatory concerns. Thus, CP&L does not rely upon any single test in performing its DSM assessment; rather it considers the result of each test in reaching its DSM decisions.

SELC witness Chernick criticized CP&L's economic evaluation of DSM programs. CP&L contended that much of his criticism is based upon his view that utilities should rely primarily on the TRC test. According to CP&L, Witness Chernick concluded that CP&L's DSM screening process is flawed because CP&L performed and relied upon all of the tests and that CP&L should be required to rely only on the TRC test in determining which DSM programs to pursue.

CP&L witness Williams also refuted witness Chernick's assertion that the RIM test should be ignored during the screening process. Witness Williams testified that only the RIM test measures a program's impact on non-participants. He said that the costs and benefits imposed directly on individual consumers by a DSM program are different for each consumer. Rate increases add an additional layer of hidden subsidy which force consumers outside of the program to pay. Programs that result in rate increases, i.e., those which fail the RIM test, result in <u>actual</u> losers because some consumers are paying higher prices for services going to someone else. These higher prices, aside from the equity issue of actual losers, are not economically efficient because the same product would sell for less were it not for a hidden subsidy. This is what the RIM test - or no-losers test, or no-cross-subsidy test, or no-rate-impact test - is all about: to see that total resource costs are actually reduced by asking those who get the benefits to pay the presumably lower costs without subsidies.

CP&L contended that a flaw in witness Chernick's suggestion that CP&L should rely primarily on the TRC test in selecting DSM programs is that the TRC test is incapable of measuring the benefits of certain DSM programs. CP&L witness Williams testified that the TRC test cannot provide a meaningful assessment of valley filling or strategic load growth programs. The reason for this shortcoming is that the TRC test ignores the primary benefit of such programs, which is the more efficient use of existing capacity as demonstrated by increases in utility revenues in excess of increases in supply costs. Under the TRC test, any change in revenues is not considered. Thus, valley filling and strategic load growth programs will always fail the TRC test. The only test that effectively measures the benefits of such programs is the RIM test.

CP&L witness Ingersoll testified that in the integration stage of the LCIRP process, CP&L combines demand-side and supply-side options in alternative resource plans. He said that, using peak load and energy forecasts which have incorporated existing and planned DSM programs, a plan which optimizes the supply-side resources to meet the remaining needs of CP&L's customers is developed. Some of the major assumptions are then tested for their effect on theoptimal plan. This is done to determine if the optimal plan is sensitive to any of the planning assumptions that are made. Using this information, several alternative plans are developed for evaluation. The assumptions that change either the type and/or timing of the resources in the optimal plan are also used as the major uncertainties for the next step of the process, the plan evaluation process.

In the plan evaluation stage, CP&L evaluates the overall value of each alternative plan. In so doing, CP&L takes into consideration the uncertainties inherent in long-term projections. Key uncertainties are evaluated using decision analysis techniques in which the uncertainties are characterized by high, medium and low values with associated probability of occurrence. The results of the analysis of the uncertainties creates various scenarios in which each of the alternate plans are assessed by simulation.

The results of the simulations are judged based on four criteria: (1) economic - based on short- and long-term revenue requirements savings; (2) financial - based on annual funds from operations interest coverage ratio; (3) environmental - based on the impact on SO_2 emissions, which is the most significant emission to be controlled under the Clean Air Act Amendment of 1990; and (4) reliability - based on impact on low reserve and high reserve margins.

In order to combine the results under each criteria into an overall ranking of alternate plans, CP&L assigns different weights to each criteria. The economic criteria is weighted most heavily at 45%. The environmental and reliability criteria are each assigned weights of 20%. The financial criteria is assigned a weight of 15%.

CP&L's use of various economic criteria enables it to select the plan that satisfies the LCIRP objectives of producing electricity at the lowest reasonable cost with due consideration for system reliability, flexibility and environmental impacts. The plan judged best overall (Plan B) was not the lowest in cost or highest in reliability but overall was the best to achieve the goals of the LCIRP process.

After a plan is selected, CP&L performs sensitivity analyses on the probabilities assigned to the outcomes for the uncertainties evolved. CP&L also performs sensitivity analyses on the weights assigned to the four evaluation criteria. Based on these sensitivity studies, CP&L concluded that Plan B was the best plan over wide ranges of uncertainty probabilities and planning criteria weightings.

CP&L's 1992 LCIRP consists of a mix of DSM programs and existing and planned supply-side resources. CP&L estimates that the amount of the summer peak load reduction capability attributable to its DSM programs will grow from 1430 MW in 1992 to 2218 MW in 2006. These figures reflect the "base" case achievements. In addition, CP&L's LCIRP stated that the Company is actively reviewing ten additional DSM programs for possible implementation in the future which may produce an additional 575 MW of DSM peak load reduction capability. Like the programs in CP&L's current DSM portfolio, the plans under consideration address a variety of load shape objectives including strategic conservation, peak clipping, valley filling, and load shifting.

With regard to supply-side resources, CP&L currently has a mix of base load, intermediate and peaking resources. CP&L's current resources represent a diverse mix of fuel types, including nuclear, coal, oil, gas and hydro. CP&L's 1992 LCIRP calls for the addition of 2,625 MW of additional capacity by 2006. All of the future supply-side capacity included in CP&L's 1992 LCIRP consists of combustion turbines, the first addition of which is scheduled to be installed in 1996. These 1996 turbines have a total capacity of 225 MW and will be installed at the Darlington County site. All capacity additions thereafter are undesignated combustion turbine capacity. In its LCIRP filing, CP&L explained that combustion turbines are in the LCIRP for several reasons. Studies continue to show that the most economical supply resource for the CP&L system is peaking capacity. This is because part of CP&L's supply strategy is to increase the utilization of its existing, dependable coal-fired capacity. By taking advantage of those valuable resources, the Company will not have to add any new base load capacity until after 2006. Combustion turbines also have short lead times; that is, they do not take long to construct. By utilizing resources with short lead times, the Company can wait until the last possible moment to make a decision to build capacity; thus, gaining the flexibility needed to respond to changing conditions. In addition, combustion turbines have low capital costs which help to minimize the need for rate increases. While the operating costs of combustion turbines are higher than other types of supply resources, analysis shows that combustion turbines retain a cost advantage even if fuel prices increase significantly.

Witness Chernick testified that CP&L was not sufficiently active in promoting its DSM programs. This opinion was based upon witness Chernick's view that in order to overcome market barriers, incentives in DSM programs shotld be set as high as necessary to achieve high participation and to encourage participating customers to install all cost-effective measures. Witness Chernick also testified that, in his opinion, rate discounts are not an effective means of addressing market barriers. Witness Chernick stated that he believed up-front loans to be more effective than rate discounts and criticized CP&L because most of CP&L's programs are informational or discount-based.

CP&L witness Harris rebutted witness Chernick's assertion that program incentives should be set as high as necessary to achieve high participation and explained that this would lead to customers being coaxed into making incorrect decisions through a central planning process involving subsidies and transfers from other consumers via rate increases.

Witness Harris also refuted witness Chernick's testimony on market barriers. He testified that market barriers are essentially hypothetical explanations to account for individuals not making seemingly good investments. He also testified that it would not be appropriate to attempt to compensate for these apparent errors (some of which he contends are not errors at all but reflections of individual preference or uncertainty as to benefits) with massive market intervention. Instead, witness Harris explained that the proper way to address market barriers is to correct them in the least costly way, thus allowing consumers to make rational decisions without subsidies from other consumers. CP&L witness Williams testified that CP&L's use of rate discounts, engineering assistance and information programs, in addition to providing low interest financing, were appropriate mechanisms for direct utility involvement in conservation.

CP&L pointed out that approximately 25,000 residential customers participate in one of CP&L's time of use programs. In addition, CP&L has made over 3,600 heat pump loans, and through program enhancements, has increased the number of loans made under its Homeowner's Energy Loan Program from 27 to over 110 per month.

CP&L uses common measures of avoided cost when evaluating both demand-side and supply-side resources. CP&L witness Ingersoll testified that the key to the Company's approach is the use of a common "avoided cost" target in demand-side and supply-side planning. The Company uses avoided costs in evaluating and determining appropriate demand-side resources for inclusion in the Company's forecasts and LCIRP. These avoided costs are updated annually. These same avoided costs are filed every two years with this Commission as required by the Public Utility Regulatory Policies Act (PURPA), and hearings are held to determine their appropriateness for use in purchasing power from qualifying supply-side facilities. This use of common avoided costs creates the linkage needed to produce a LCIRP in a straightforward, cost-effective, and consistent manner.

SELC Witness Chernick contended that the design of CP&L's Common Sense Home Program and Residential High-Efficiency Heat Pump Program is deficient. Witness Chernick proposed that the Commission require CP&L to immediately redesign these programs to address these deficiencies.

CP&L's Common Sense Home Program is intended to promote conservation by encouraging the construction of energy-efficient homes. The program provides a rate discount for structures that meet program standards for thermal integrity and equipment efficiency. The program includes standards for insulation, window design, electric hot water heaters and heat pumps. Witness Chernick asserted that the program should include incentives for other measures such as low-E windows. Witness Chernick also contended that the program standards for insulation light be too low because they will not differ much from the revised North Carolina building code (expected by January 1993). Similarly, witness Chernick contended that the minimum efficiency levels for heat pumps were too low because they are the mhnimum efficiencies required by federal law.

CP&L witness Williams explained that at the time the Common Sense Home Program was established the insulation standards in the program (R-30 ceiling, R-16 walls and R-19 floors) exceeded existing State building code standards (R-19 ceiling, R-11 walls and R-11 floors). Moreover, the common sense home criteria refer solely to insulation while the North Carolina building code refers to composite ceilings and walls. Thus, the correct rating of CP&L's insulation requirements, taken as <u>composite</u> ceilings and walls (R-32 ceiling, R-19 walls, and R-24 floors), exceed the newly revised North Carolina building code. Finally witness Williams testified that CP&L enhanced the program's standards in mid-1992 by requiring R-7 perimeter insulation for slab floors, which exceeds the code requirements and that CP&L currently is reevaluating its Common Sense Home standards in light of the recent revisions to the North Carolina code.

With regard to the efficiency levels for heat pumps, witness Williams testified that the federal standards to which witness Chernick referred only prohibited the <u>manufacture</u> and not the sale of split system heat pumps with a SEER of less than 10 after January 1, 1992. Thus, there is a substantial inventory of less efficient heat pumps available for use in new homes. Witness Williams also noted that CP&L plans to reevaluate its efficiency standards for heat pumps in 1993.

Witness Chernick's criticism of CP&L's Residential High-Efficiency Heat Pump program was essentially the same as his criticism of the heat pump option of the Common Sense Home Program. That is, he said the efficiency standards encouraged are too low. Witness Williams testified that CP&L's loan program not only provides financing for heat pumps but ties the level of the financing to the efficiency of the heat pump. Thus, while financing is available under the program for heat pumps with a SEER of less than 11, CP&L witness Williams testified that 80% of the participants in the program have installed heat pumps with a SEER of 11 or greater.

<u>Duke Power Company</u>

Duke witness Denton testified that the demand-side planning process begins with an assessment of the energy consumption patterns in the marketplace and the end-use technologies currently being used by customers. A comparison is then made to assess the potential beneficial impact new technologies or approaches may have on customer energy consumption patterns. In addition, existing DSM program approaches and technologies are reviewed to determine if changes or enhancements are required for the future.

Of the 24 demand-side options reviewed in the 1992 planning cycle, 22 options fall into three broad categories: energy-efficiency (14), load shifting (1), and interruptible (7). The two remaining options focus on opportunities for electric technologies to aid customers in making environmental quality improvements. The 14 energy-efficiency options target areas involving water heaters, refrigerators, freezers, heat pumps, central air conditioners, chillers and unitary systems for air conditioning, indoor lighting, insulation, and motor systems. The seven interruptible options target load control of residential water heaters and air conditioners, activation of standby generators and interruption of industrial processes. The two environmental options target recovery of plating solutions in metal finishing operations and the reduction of waste water effluent in textile operations. The one load shifting option focuses on residential water heating. Twenty-one of the 24 demand-side programs were forwarded to the integration process.

SELC witness Chernick contended that there were several omissions and deficiencies in the Company's DSM portfolio. Witness Chernick stated that Duke fails to target DSM market sectors comprehensively, resulting in lost opportunities. He also testified that Duke hgnores two lost-opportunity segments altogether: non-residential new construction and renovation and the industrial process changes in new factories, plant expansion and refurbishment. Witness Chernick indicated that new construction provides opportunities for a wide range of efficiency improvements.

Witness Denton testified in rebuttal that Duke's DSM programs cover a number of markets and end-uses. As the Company expanded its commitment to DSM, Duke concentrated its DSM option design efforts on those markets and end-uses where the greatest impact could be achieved. To avoid discrimination between customer groups, Duke offers programs to as many market segments as possible. For example, Duke concentrates on heating and cooling in the residential sector, and lighting, motors and HVAC in the commercial/industrial sectors since these end-uses account for the majority of energy use.

Witness Denton testified in rebuttal that Duke has bundled several residential DSM programs together to address the residential new construction market. He noted that Duke has not made the same consolidation in the non-residential construction market because of the large number of variables that impact the design of a new construction program. However, Duke is conducting a DSM Resource Assessment which will provide much of the data needed to enable Duke to design a comprehensive non-residential new construction DSM program. Likewise, Duke will continue to evaluate specific industrial process options in order to address a similar diversity in the industrial process market. In this regard, Duke has also implemented a DSM bidding program which will allow industrial customers to identify many unique DSM opportunities.

Witness Chernick alleged that several of Duke's programs can be expected to result in cream-skimming. He testified that cream-skimming renders otherwise cost-effective resources non-cost-effective or more difficult to obtain savings. He explained that cre'm-skimming can occur if a DSM program captures a certain amount of savings but at the same time renders other DSM programs less cost-effective or more difficult to obtain savings.

In rebuttal witness Denton testified that Duke designed its programs to be as cost-effective as possible while covering as many markets as possible. To seek all cost-effective conservation measures within a program at one time would mean higher incentives, which in turn limits the financial resources available to offer other DSM programs. As Duke has expanded its DSM offerings, the Company has deliberately sought to offer a balance of cost-effective programs to all sectors on a timely basis.

Witness Chernick testified that Duke's existing DSM programs do not adequately address market barriers, noting particularly that Duke lacks a mechanism for targeting trade allies. He stated that Duke must work with trade allies to ensure that they have sufficient stocks of high efficiency equipment. By offering incentives to dealers, Duke can raise the efficiency of in-stock equipment available to its customers.

Witness Denton testified that Duke strives to address market barriers in its program design. He noted that one method of addressing barriers is to utilize pilot programs to identify existing barriers and ways to overcome them.

Duke witness Hendricks testified that the supply-side planning process is initiated with an up-to-date review of available technologies. This includes review of Electric Power Research Institute and other industry data, research by other utilities, and research conducted by Duke. Certain technologies which are not feasible in the Duke service area are eliminated. Duke develops schedule, cost, and performance data for the remaining technologies. These remaining technologies then undergo a screening analysis that indicates which technologies are low cost or cost competitive over a range of capacity factors. The technologies selected by the screening analysis are then passed to integration for evaluation using expansion planning modeling techniques.

A total of 33 technologies were initially considered, ranging from conventional technologies such as pulverized coal, combustion turbines, combined cycle, and nuclear to emerging technologies such as advanced batteries, solar, and photovoltaics. Conventional pulverized coal, atmospheric fluidized bed combustion, circulating fluidized bed combustion, light water nuclear reactors, pumped storage hydro, combustion turbines, combined cycle, diesel generators, phosphoric acid fuel cells, and advanced battery technologies passed the detailed screening process and were forwarded to the integration process.

Witness Hendricks also discussed the impact of the Clean Air Act Amendments (CAAA) of 1990 and externalities on supply-side planning. Title IV of the CAAA requires significant reductions in annual emissions of sulfur dioxide (SO2) and nitrogen oxides (NOX) by the year 2000. The primary impact of this requirement will be on Duke's eight fossil stations. Duke has the flexibility of time and multiple compliance options to develop and implement a sound, cost-effective compliance strategy by the year 2000 when Duke is required to comply with Phase II of the CAAA Title IV.

Witness Hendricks testified that Duke is taking advantage of the interim time period to develop a strategy to meet Phase II requirements of Title IV and to follow the development of remaining Phase II requirements. He testified that the preliminary compliance plan was an input to the LCIRP process and that the final compliance plan may be significantly different based on development of regulations and technologies.

Witness Hendricks testified that Duke has researched a variety of reference documents on the subject of environmental externalities and Duke believes its present methods of considering environmental externalities are appropriate. Duke plans to continue to monitor and evaluate developments regarding externalities. Duke will continue to include the costs of environmental compliance in its assessment of resource options and will continue to qualitatively consider environmental effects in resource assessments.

CIGFUR witness Phillips testified that great care must be taken in considering externalities beyond those that are rather obvious such as zoning ordinances, land-use restrictions and cultural factors. He noted that factors such as air or water emissions are extremely difficult to quantify. He testified that it is reasonable to assume that the legislative bodies and agencies establishing pollution control requirements have taken these factors into account in developing the standards that must be met.

Witness Reinke testified that an integrated resource analysis would not be complete without determining whether purchased resources from non-utility generators (NUGs) or other utilities would be feasible options and allow postponement of other resources. Consequently, Duke keeps abreast of purchased power opportunities through periodic contacts with other utilities, selective solicitations for quotes for power and evaluation of requests for proposals of other utilities. Purchased resources which appear to be economically attractive and technically viable are pursued through further negotiations. Once a contractual agreement is reached, the purchased resource is included in the integrated planning process.

Witness Reinke testified that Duke will continue to examine proposals made by other entities to construct generating facilities on the Duke system and supply electricity to Duke from those facilities. He also testified that Duke is developing a competitive bidding process and a request for proposals (RFP) which can be utilized for future capacity needs. Witness Reinke indicated that the RFP for supply-side resources would not be needed until Duke is within or at the front end of the window of lead time required for supply-side resources.

Duke witness Reinke testified that resource integration is accomplished through extensive use of computer models which stimulate power system operation. Initially, the fundamental assumptions in the previous plan are modified to reflect current conditions (Updated Plan). The Updated Plan is used to develop an optimal Base Supply-Side Plan, which is the plan that produces the lowest total present worth of revenue requirements over the study period considering only supply-side options. The Base Supply-Side Plan resulting from the 1992 LCIRP process included about 3500 MW of combustion turbine capacity from 1992 to 2006, and 2400 MW of coal capacity from 2003 to 2006.

Witness Reinke explained that DSM option integration begins with the economic evaluation of each DSM option in the Single Option Analysis. Single Option Analysis evaluates each of the DSM options one at a time against the Updated Plan and determines the overall benefit of each option. Cumulative Option Analysis uses the Single Option Analysis results to reevaluate the DSM options in ranked order. This method recognizes the synergism which occurs among options and with the existing system. Several planning models are used to determine each DSM option's benefits and costs by determining the production and capacity impacts. These impacts along with financial data associated with each option result in the computation of a benefit/cost ratio for several different economic tests.

Witness Reinke described four economic tests in his testimony. The first of these is the Participant Test which evaluates the benefits for potential participants compared to their costs. This test evaluates whether the customer is likely to participate in a proposed program given the investment the customer might have to make compared to the bill savings along with any proposed utility incentive. The Total Resource Cost (TRC) test determines the benefits to all customers compared to the total costs. The Utility Cost (UC) test measures the impact on utility bills resulting from the implementation of the program. The Rate Impact Measure (RIM) test determines the impact on electricity prices for implementation of a program.

Witness Reinke testified that using the Benefit/Cost ratios from the Cumulative Option Analysis, the supply-side options from the Base Supply-Side Plan and purchased power agreements, alternative plans are developed. Four alternative plans, including the Base Supply-Side Plan, were developed for the 1992 LCIRP.

The results obtained to this point from the integration process are for a fixed set of conditions. The alternative plans were subjected to an evaluation which considered uncertainties in the underlying assumptions in the Risk Assessment phase of the study. Witness Reinke explained that risk assessment addresses, through both objective and subjective analysis, the risks and uncertainties of forecasting the future. These uncertainties could be recognized through examinations of various individual assumptions. Studying a series of alternative plans under these various conditions makes it possible to identify those plans which would remain attractive in an uncertain future.

In regard to his evaluation of Duke's integration process, SELC witness Chernick testified that the Company did not screen several existing residential DSM programs. He stated that an earlier screening was of no value for this proceeding since avoided costs used in any previous screening are likely to be different than those Duke now uses.

Duke witness Denton testified that Duke did not analyze existing programs where those programs did not experience a significant change in assumptions since the 1991 LCIRP analysis. All existing programs were analyzed in the 1891 LCIRP process and included in the 1991 Short Term Action Plan (STAP). The programs not analyzed in the 1992 LCIRP process were cost-effective in the 1991 LCIRP process and results would have been similar in the 1892 LCIRP process. Because the major assumptions regarding program costs, program accomplishments, rebate levels, etc., did not change, Duke chose not to reanalyze these options in the 1992 process. While it is true that capacity and energy costs change with each LCIRP process, the change was not significant from the 1991 to the 1992 process. Had all programs been analyzed in the 1992 LCIRP process, changes in the results would have been insignificant and there would have been no change in the final plan selected. Mr. Denton further noted that Duke analyzed all DSM programs in its 1993 LCIRP process.

Witness Chernick testified that the Company's reliance on the RIM test to rank options for the Cumulative Option Analysis may result in a suboptimal selection of DSM programs. Witness Denton testified in rebuttal that Duke used the RIM test for ranking DSM options in the single option analysis, but no DSM options were screened out at this stage of the process.

SELC witness Chernick testified that the utility should rely primarily on the TRC test, stating that only the TRC test will consistently reflect the true value of efficiency programs. Witness Chernick stated that any measure that passes the TRC screening is worth pursuing. He stated that the Utility Cost test has a largely conceptual role in fine-tuning program design and should not be used to determine whether actions are cost-effective.

CIGFUR witness Phillips testified that the Participant and the RIM tests provide the most useful information for evaluating DSM. He stated that the RIM test is the only test that considers all relevant information about the cost of the DSM measure to utility ratepayers and the impact of the measure.

Witness Denton noted that in the May 17, 1990, Order in Docket No. E-100, Sub 58, which adopted the utilities' 1989 LCIRPs, the Commission stated that "(t)he Commission agrees that a preference should not be cited or adopted for a single test." The Order also approved stipulations between the utilities and the Public Staff which included agreement by the utilities not to limit the screening analysis of DSM options to a single criterion only, such as the RIM test, but to continue to pursue a comprehensive assessment that considers and balances the results of multiple criteria. He stated that Duke complied with this Order in developing its 1992 LCIRP.

Witness Denton also testified that no single test includes all relevant factors. For example, the TRC test does not include credits or rebates paid to the customer. The TRC test does not consider rate impacts of a program. It is important to recognize the rate impact on other customers, as measured by the RIM test, when evaluating options which pass the TRC test. Duke uses multiple tests to evaluate the impact on all rate classes and customers, not just those that participate in the DSM programs.

Witness Chernick testified that Duke's DSM planning process does not seek to maximize net benefits. Among those competing mutually-exclusive DSM decisions that pass the TRC test, the one delivering the maximum net benefit should be selected. He contended that the objective of least-cost planning is to minimize total resource costs, and this goal can only be achieved by selecting actions that maximize the difference between the DSM benefits and costs. Therefore, he concluded that DSM screening should not seek to maximize the benefit/cost ratio of the DSM portfolio of individual programs or measures.

Witness Denton testified that Duke is convinced that the use of benefit/cost ratios provides the greatest net benefits per dollar spent on DSM programs. Duke has chosen to implement a number of programs aimed at a large segment of the market rather than a limited number of programs or limited participation in the programs. He testified that increasing expenditures in a particular program in an attempt to achieve more energy and capacity savings simply redirects the financial resources away from other programs which may be reaching markets not otherwise affected by DSM.

With regard to pilot projects, SELC witness Chernick testified that the Company has not demonstrated that its pilots are appropriate to an LCIRP. Pilot programs are justified to test innovative program designs and build the capability to produce program results. He noted that other utilities have implemented programs that offer many of the technologies Duke is piloting. He argued that Duke should attempt to pursue new DSM programs as full-scale demonstration programs rather than limited pilots.

Duke witness Denton stated that Duke believes pilots provide a valuable means to clarify the uncertainties in DSM design and implementation, thereby increasing the chances of success and reducing risks. Some examples of these uncertainties are costs, customer acceptance, load shape impact and technology performance. Witness Denton stated that Duke plans to continue this valuable practice of piloting new demand-side concepts for those new options that need to be tested in the marketplace before system-wide implementation.

Witness Denton also testified that it is difficult to directly transfer a DSM program from one utility to another because there are differences in customers, climates, system economics, and other factors that cannot easily be analytically overcome. He further testified that Duke has been involved in the energy marketplace for many years and has raised the service area's awareness of energy conservation. This awareness may increase the level of free-riders associated with a program, as opposed to an area where conservation and load management are relatively new. He noted that programs are only cost-effective if the avoided capacity and energy costs are greater than the costs as measured by the various tests. Duke's avoided capacity and energy costs are lower than many utilities. This situation further emphasizes the need for pilot projects in the Duke service area.

CIGFUR witness Phillips testified that experience in other geographic areas with DSM programs must be explicitly modified to take differences into account. He stated that it would be desirable to conduct experimental DSM programs to gain relevant experience before attempting to incorporate substantial DSM options into the LCIRP. In addition, the Public Staff agreed that pilot projects improve planning data. Public Staff witness Warwick testified that in areas where utilities did not properly utilize pilot programs, they learned high cost lessons.

Witness Plett, representing Allied-Signal, a manufacturer of amorphous metal for transformers, presented testimony on transmission/distribution efficiency opportunities. He stated that the purpose of his testimony was to communicate the potential benefits of more efficient transmission and distribution equipment. He testified that the appropriate test is to compare "total owning costs" of transformers.

Duke points out that its 1992 LCIRP states that Duke has pursued economical and efficient design in transmission and distribution facilities to ensure service reliability and needed operational flexibility. Along with capital, maintenance and other operation costs, the cost of losses associated with equipment and conductors has been considered when making system changes. When Duke requests bids for distribution transformers, the vendor quotes a price based on total owning cost of the transformer. The LCIRP further states that, to date, even though amorphous core transformers inherently have low loss characteristics, no vendor has quoted amorphous core transformers that have lowest total owning cost.

On cross-examination, witness Plett indicated that he is aware that Duke is presently utilizing amorphous core transformers on its system and that Duke instructed manufacturers to bid amorphous core transformers in 1992. Witness Plett also indicated that his calculation of savings to North Carolina electric customers from the use of his company's product did not include the capital cost of the amorphous core transformer.

Empire witness Greenberg commented on the LCIRP submitted by Duke and also proposed including Empire's own CT units in addition to Duke's Lincoln units. Empire is seeking to develop Rolling Hills, a 600 MW combustion turbine power plant in Rockingham County, from which it proposes to sell peaking power to Duke and CP&L. Witness Greenberg testified that Cogentrix, Inc., would design, build, operate and own part of the Rolling Hills project.

Witness Greenberg testified that, for purposes of evaluation, Empire adopted Duke's gross peak load forecast, provided alternate scenarios for DSM peak load reduction capacity, and calculated what a 20% reserve margin would require in additional supply-side capacity. Witness Greenberg contended that Duke's forecast contains such high growth in DSM peak load reduction that its supply-side reserve margin falls to 2.2% in 2004. Empire calculated a 10% supply-side reserve margin for each year of the forecast period, compared this level of resources with the level planned by Duke, and noted a resulting "reserve deficit". Witness Greenberg testified that it is imprudent to back out supply-side resources to reserve margin levels of less than 10% and is more prudent to plan for additional generation.

Witness Greenberg proposed that capacity from Empire's Rolling Hills project and additional undesignated CT capacity be used to meet the deficit which Empire calculated to exist in Duke's LCIRP. One schedule for capacity additions proposed by Empire provides for a full 600 MW purchase from Rolling Hills by Duke, while another schedule provides for a 300 MW purchase by Duke and a 300 MW purchase by CP&L.

Duke witness Reinke acknowledged that Duke Exhibit 11-6 shows generating reserves in the low single digits. However, this exhibit does not reflect the capacity-equivalent numbers of energy efficiency programs which, when implemented, will result in a lower load forecast and higher generating reserves. Duke's minimum planning reserve margin is 20%.

Duke noted that Empire's application for a certificate of convenience and necessity for the Rolling Hills project was dismissed (but is on appeal) and Empire has not yet filed its air permit application.

Empire asserted that it has an on-going relationship with Cogentrix for construction of the Rolling Hills project. Witness Greenberg acknowledged on cross-examination that Cogentrix has forwarded a letter to Empire indicating that it would no longer be a party to the Rolling Hills project. The letter also indicated that Cogentrix would not be a party to a project which used litigation or similar actions as a means of obtaining a purchased power agreement.

Witness Denton summarized the results of the 1992 LCIRP process. Duke's LCIRP results in a mix of resource options which will provide an adequate and reliable supply of electricity to Duke's customers in a cost-effective manner. The LCIRP reflects cumulative demand-side capacity equivalent to 3689 MW by 2006. He also noted that DSM represents 47% of the system capacity resource additions over the 15-year planning period.

Witness Denton testified that the LCIRP reflects operation of the Lincoln Combustion Turbine Station beginning in 1995. The LCIRP also calls for 1280 MW of additional combustion turbines (CTs) in 2002 through 2005 and a 600 MW base load fossil unit in 2006. Witness Denton also testified regarding Duke's STAP which sets forth the necessary preparation to maintain a 1995 operation date for the Lincoln CT units.

Witness Reinke testified that Duke's 1992 LCIRP includes 48 MW of firm purchased capacity from NUGs. He also testified that the firm capacity from NUGs has recently been revised to 55 MW to reflect new contracts but that the increase would not have a material impact on this LCIRP. He further testified that no specific values for future NUG capacity additions are included in this LCIRP because Duke does not include such capacity until it is under contract. He indicated that this does not mean that Duke would not include additional NUG capacity as part of its future LCIRP.

Witness Reinke testified that Duke is concerned about having an overabundance of interruptible programs as a large part of its reserves. Witness Denton added that one major reason to move ahead with the Lincoln CT units is to bring interruptible capacity back into balance with generation.

The Public Staff panel of Warwick and Foley indicated that Duke has demonstrated good faith in its efforts toward integrated resource planning. The panel was of the opinion that Duke's current LCIRP is adequate for near term decision making regarding DSM programs. Additionally, compliance with the proposed November 6, 1992, stipulation will ultimately result in a plan suitable for both near and long term resource decisions. The stipulation involves end-use forecasting, DSM assessment, resource integration and treatment of uncertainty. The panel indicated that the Commission can approve DSM programs in an LCIRP even though planning is ongoing. The panel concluded that with the current plans and the stipulations, North Carolina is moving in the right direction for LCIRP.

SELC and Duke entered a stipulation dated December 1, 1992, which was filed as Duke-Denton Exhibit 2 in this docket. The stipulation sets forth issues of concern to SELC regarding Duke's LCIRP process. Specific issues addressed in the stipulation include general principles of integrated resource planning, new DSM programs, DSM pilot programs, existing and proposed DSM programs, information to be provided in Duke's next STAP, and DSM cost recovery and incentive mechanisms.

The stipulation recognizes SELC's belief that Duke's LCIRP reflects a significant expansion into conservation and efficiency and its belief that an ongoing dialogue with Duke is an effective forum in which to address its concerns. As part of the stipulation, SELC withdrew certain specific recommendations to the Commission regarding Duke's LCIRP contained in Witness Chernick's prefiled direct testimony.

<u>North Carolina Power</u>

NC Power witness O'Neil adopted the prefiled testimony of Larry W. Ellis. He presented an overview of the Company's LCIRP objectives and the planning process by which those objectives are achieved, including the criteria by which the Company selects its approved package of DSM programs. Witness O'Neil also addressed a number of developments in NC Power's planning process, including its performance of a Reserve Margin Review in 1991, the Company's plans to implement demand side bidding in conjunction with supply side bidding in its next solicitation, the Company's rate design strategy, the results of the Company's comprehensive evaluation of its DSM activities through the use of Richard Metzler and Associates in 1991, and the Company's incorporation of a compliance strategy reflecting the requirements of the 1990 Clean Air Act Amendments into its 1992 LCIRP. Finally, witness O'Neil introduced the formation of the Energy Efficiency Group, whereby the Company centralized its DSM activities into one organization. The reorganization resulted in a $7 million annual increase in the Company's DSM budget over the budget relied upon in developing the Company's 1992 LCIRP.

NC Power witness Doswell sponsored the conservation and load management portion of the Company's filing. Witness Doswell discussed a number of improvements in the Company's DSM planning activities, including the Company initiated evaluation of DSM activities performed by Richard Metzler and @cecitis. Her discussion reflects the Company's expansion of market research, end-use load research, DSM cost and participant tracking, DSM research, DSM program identification and screening, DSM cost effectiveness evaluations and DSM documentation. Witness Doswell also addressed the appropriateness of the consideration of "end effects" in the evaluation of DSM programs, the Company's proposed experimental DSM bidding program and the proper method of determining cost-effectiveness for DSM programs included in the Company's approved DSM portfolio. Finally, witness Doswell introduced the Company's 1992 DSM plan, described the Company's new DSM programs and discussed the forecasted reduction in peak load resulting from those DSM programs.

NC Power witness Newcomb discussed the Rate Department's role in the Company's LCIRP process and the use of pricing to encourage customer load management. He also discussed future rate initiatives planned by the Company to influence customer purchase decisions and the development of a class revenue model as a new rate planning tool.

NC Power witness Ross presented an overview of the Company's supply side resource options and discussed the Company's existing generating facilities, planned generation additions, alternative energy resources, purchased power resources and improvements to the Company's transmission/distribution facilities. Witness Ross also described improvements the Company has incorporated into its supply-side planning strategy such as its diversity exchange agreement with Allegheny Power System, a sales agreement with South Carolina Public Service Authority, a 1991 review of the Company's long term target reserve margin and the Company's development of a compliance strategy in response to the requirements of the 1990 Clean Air Act Amendments.

The testimony of Paul L. Chernick, on behalf of the SELC, was stipulated into the record. He performed a comprehensive review of Duke's LCIRP and a less defined review of the LCIRPs of CP&L and NC Power. Witness Chernick recommended that the Commission establish certain "general principles" for all utilities to follow in developing LCIRPs. He proposed that the Commission rely primarily upon the total resource cost (TRC) test in selecthng and implementing DSM programs and supported utility payments of maximum incentives to encourage DSM. He also addresses a number of other DSM issues related to load building programs, comprehensive strategies for planning and acquiring DSM resources, lost opportunity resources, cream skimming and DSM program design. Witness Chernick ultimately concluded that the LCIRPs of CP&L, Duke and NC Power do not represent the utilities' least cost plans.

The rebuttal testimony of NC Power witness Doswell was also stipulated into the record. Witness Doswell's testimony refuted specific portions of witness

Chernick's testimony, including the role of economic tests in the screening and analysis of DSM options and the appropriateness of NC Power's use of cost/benefit tests in its analysis of DSM programs.

The primary issue raised by the SELC in this docket involves the appropriate cost/benefit test(s) to be applied in the assessment of DSM alternatives. The SELC supports primary reliance upon the total resource cost (TRC) test while criticizing the remaining standard tests. For instance, witness Chernick indicates that any DSM measure that passes the total resource cost (TRC) test is worth pursuing. He indicates that the rate impact measure (RIM) test should have no role in determining the cost effectiveness of a demand side resource. He also concludes that, since the costs that flow through utility rates are not all of the costs of DSM, the utility cost (UC) test should not be used to determine whether DSM programs are cost effective. Finally, witness Chernick implies that the cost/benefit ratio for the participants test is meaningless. NC Power contends that witness Chernick's application of the TRC test, to the virtual exclusion of other standard tests, results in a distinct preference for conservation programs over other forms of DSM.

There are four basic cost/benefit tests. They include the participant test, utility cost (UC) test, ratepayer impact measure (RIM) test, and the total resource cost (TRC) test. These standard cost/benefit tests are applied to DSM programs because there exists a need to measure costs and benefits from multiple perspectives such as program participants, non-participants and the utility. In essence, each test provides part of the total information potentially available regarding the impact of a particular DSM program. A more complete picture emerges when all of the tests are applied to a particular DSM program.

NC Power points out that most demand side programs will pass a cost/benefit test from the perspective of a least one stakeholder. However, rarely will a program be cost effective from all perspectives. For example, many conservation programs pass the TRC test but do not pass the RIM test. Those programs that adversely impact non-participants are often evaluated further to see if changes in program design can be made to mitigate rate increases. Although some programs can be modified, decisions regarding trade-offs between adverse impacts on non-participants and the benefits of resource efficiency shown in the TRC test are frequently required.

NC Power also points out that there are a number of limitations that are characteristic of all the tests. For instance, the tests do not incorporate factors that are unquantifiable; thus key factors influencing decisions will be missed. The tests also require a great deal of data, some of which has already been developed by the utilities, but some of which is difficult to obtain. The Public Staff and the utilities have addressed the development of additional data through the stipulations filed in this case.

Witness Chernick criticized NC Power's Energy Saver Homes (ESH), Energy Saver Systems (ESS) and Commercial Heat Pump Programs due to the fact that they include certain load building characteristics. Witness Chernick's criticism of load building programs focuses primarily on the fact that these programs do not pass the TRC test.

NC Power pointed out that most load building programs do not pass the TRC test. This is because such programs consume fuel resources with the offsetting quantifiable benefit of few new plant resources, even though the programs result in more efficient use of the existing power supply system. NC Power contends that the difficulty that load building programs have in passing the TRC test is not a major impediment to the application of a multi-perspective set of tests. It is simply another example of the need to recognize what benefits and costs are included in each test and how to apply them.

Witness Chernick also criticizes NC Power for its failure to implement the Company's Commercial Indoor Efficiency Lighting Program which includes rebates for customer conservation investments, in Virginia.

NC Power pointed out that the Company was prohibited by the Virginia State Corporation Commission (SCC) from the use of "promotional allowances" in the Company's primary jurisdiction at the time the 1992 LCIRP was developed. The Company also pointed out that the SCC's ban on promotional allowances has been relaxed to some degree and that the Company is prepared to implement its Pilot Commercial Indoor Efficiency Lighting Program, including the use of financial incentives, in its 1993 LCIRP. Similarly, the Company has acknowledged the need to gain a greater understanding of the role that significant incentives can be expected to play in future DSM programs through the review of other utilities' experiences, joint utility projects, efforts coordinated through third parties (such as the North Carolina Alternative Energy Corporation) and future pilot DSM programs. Furthermore, while the SCC's limitations on the use of promotional allowances may have influenced the speed with which the Company has developed and expanded certain programs to enhance energy efficiency among new customers, the Company and the Public Staff stipulated that if and when these constraints are further relaxed, the Public Staff may press for a change in the Company's approach to DSM programs involving promotional allowances.

Nantahala

Nantahala witness Tucker testified that Nantahala's generating system consists of eleven small hydroelectric plants with a total capability of about 89 MW. The level of generation available from the hydro system varies substantially from year to year based on the amount and timing of rainfall. The maximum load on the system occurs in the winter, and was 207 MW during the most recent winter season. Therefore, Nantahala's generating capability is not sufficient to serve its customers.

Witness Tucker testified that Nantahala entered into long-term power supply contracts with Duke in 1987 that became effective in October 1990. The Duke agreement provided for a firm supplemental power supply at system average embedded cost. Also, Duke has taken on a public service obligation to provide a firm long-term source of power to Nantahala. Duke must plan and construct its system to meet the future needs of Nantahala's customers. Duke's filed LCIRP includes Nantahala's total requirements and generation as part of Duke's load and available resources.

Witness Tucker testified that Nantahala's activities in promoting conservation in its service area are largely educational. He cited the RC rate schedule which is a reduced residential rate for meeting certain insulation standards in excess of building code requirements.

Witness Tucker testified that Nantahala plans to expand its efforts in the conservation and load management area. Recently, Nantahala created a full time position responsible for the design and implementation of load management and conservation programs on Nantahala's system. Nantahala will review and analyze various proposed programs to determine whether they appear to be economically justified on the Nantahala system. To proceed with a new program, the analysis must indicate that the net savings from the program are greater than the cost of purchasing the corresponding power from Duke. Programs may also be reviewed for implementation on the Nantahala system on the basis of their impact on the operations and costs of Duke. Such a program may not on its face present a significant savings to Nantahala but may provide major savings to Duke. Reducing costs to Duke will in the long run reduce Nantahala's costs as well.

Witness Tucker testified that Nantahala does not have the manpower resources or detailed knowledge to fully analyze many of the new load management and conservation technologies as they develop. The approach that will be used will be to review programs that have been analyzed by Duke or other companies. These programs will be investigated to determine their applicability to Nantahala's system. If found to be economically justified they will be utilized as is or modified for implementation by Nantahala.

No other party challenged Nantahala's planning process.

Public Staff

The panel consisting of witnesses Warwick and Foley testified on behalf of the Public Staff. The consultants indicated that they had been retained by the Public Staff to review the resource planning processes underway at CP&L, Duke and NC Power as well as the progress made from stipulations reached by the utilities and the Public Staff in the initial least cost proceeding. The panel stated that the approach used in conducting their investigation and review was to request and review LCIRP documents, conduct interviews of kex utility personnel involved with least cost planning, analyze the information received, and develop findings and conclusions.

A major conclusion of their review is that the North Carolina utilities continue to make progress in resource planning and adoption of LCIRP methods. The consultants found the staff at each utility to be competent, capable and professional as well as highly motivated, and they determined that the current LCIRP documents were improved over the documents submitted in the 1989 filings. The panel also testified that several areas, especially those associated with the comprehensive treatment of energy efficiency and load management programs and their integration into utility plans, required improvement. The panel also sponsored their report entitled "Least-Cost Integrated Resource Planning in North Carolina: Review, Interpretations and Recommendations." The consultants' report contained numerous findings and recommendations and an estimate of the cost of implementing those recommendations.

Witness Warwick offered a joint summary of the consultants' testimony and report for the panel. He indicated that the recommendations in this proceeding are similar to those in the first case and that, while the utilities' progress towards the recommendations from the initial case were not as prompt as desired, the efforts in this case were aided by the good faith of the utilities and the Public Staff and their mutual efforts to gain a better understanding of all of the ramifications of the past and current stipulations. Witness Warwick also acknowledged the willingness and desire of the utilities to embark on activities to achieve the objectives of the stipulations, resulting in a better understanding among all parties about the meaning of LCIRP and how to best implement it.

Witness Warwick focused upon four recommendations in the summary. The consultants stressed the need for the adoption of end use forecasting models and for corresponding data collection to ensure that end use model results are on an equal footing with econometric results. They support the conduct of DSM assessments by use of a supply side curve methodology. The consultants also encouraged the utilities to expand their uncertainty analyses in the integration stage in order to provide the companies with a better understanding of the risks inherent in current planning approaches and the value of DSM programs 's insurance against an unknown future. Finally, they emphasized the need to develop aggressive energy efficiency programs aimed at new customers due to the fact that these programs provide immediate benefits to hold down peak growth and they ultimately help to forestall new base load plants to the benefit of all customers. These recommendations were the subject of specific stipulations between the utilities and the Public Staff.

The consultants estimate that the recommended activities, assuming collaboration among the three utilities, will increase utility costs by approximately $19.8 million in 1993; $24.7 million in 1994; $47.1 million in 1995; and $37.54 million in 1996. More importantly, the consultants indicate that this cost will be repaid in a timely manner. The data, analysis and recommendations will provide a much firmer basis for utility estimates of the need for new power plants. The benefits will also include utility implementation of programs that will achieve additional reductions in annual electricity use as well as peak demands. These programs should be designed to save money for customers, reduce the need to build new power plant transmission lines in North Carolina, reduce emissions of greenhouse gases and other pollutants, improve economic productivity and improve the financial performance and of the North Carolina utilities.

<u>Empire Power</u>

Empire contends that CP&L conceded in the hearing that the counterclockwise flow of electricity from the southeastern Duke system to the southwestern CP&L system, and from the northwestern CP&L system to the northeastern Duke system, is detrimental to the CP&L system.

Empire also contends that CP&L conceded at the hearing that the best location for future generating capacity on the CP&L system is Brunswick County, although the Company currently plans to add more combustion turbines at its Darlington, South Carolina plant. Empire contends that Duke conceded at the hearing that the best location for future generating capacity on the Duke system is the northeast quadrant of its system, although the Company currently plans to add more combustion turbines at its Lincoln County site.

Empire proposes to build a generating station at its Rolling Hills site in the northeast quadrant of the Duke system, where it would alleviate the counterclockwise flow of the Duke/CP&L interconnection. Empire also proposes that CP&L and Duke be required to study the impact of additional generating capacity at the Brunswick County, Darlington, Lincoln County and Rolling Hills sites on the interconnection between the two utilities, and report their findings in their next short term action plans.

Empire also contends that the load forecasts of CP&L and Duke both overestimate the effect of DSM programs in reducing their peak loads. It contends that they have not accounted for needed retirements of some generating units during the forecast period. It said their need for generating capacity over the next 15 years is greater than they have acknowledged, and it will result in reserve margins of less than 20% most of the time. Empire proposed that the Rolling Hills project would be a good solution to CP&L's and Duke's need for additional capacity. Empire also proposed that CP&L and Duke be required to study the remaining useful life of their existing combustion turbines and report their findings in their next short term action plans.

Conclusions

The Commission commends the utilities, the Public Staff and SELC for their efforts to achieve the stipulations filed herein. Their efforts in this regard have greatly simplified the Commission's work in this docket.

The Commission recognizes that LCIRP is an evolving, dynamic process, and that new information and new understanding on planning principles will continue to be developed in the future. The LCIRPs filed herein reflect the utilities' evaluation of a full range of resources, including conservation, load management and energy efficiency programs well as alternative energy resources, in order to meet expected future demand. In conclusion, the LCIRPs of CP&L, Duke and NC Power combined with the stipulations between the utilities and the Public Staff, comply with the Commission's LCIRP rules while recognizing the need to continue utility efforts to enhance their LCIRP processes. For purposes of this proceeding, each of the LCIRPs should be approved.

The Commission notes that Duke's LCRIP includes significant DSM program targets. The cumulative maximum net dependable DSM capacity grows from a value of 1165 MW in 1992 to 3,689 MW by 2006. By 2006, DSM is projected to contribute 64% of the additional system energy requirements. Duke's LCRIP provides for implementing two new DSM programs and for piloting a variety of DSM concepts. Pilot programs allow new concepts to be tested in the marketplace before large expenditures are made for system-wide implementation. The Commission commends Duke's efforts, including its emphasis on DSM programs and its aggressive pursuit of pilot programs. Duke is moving in the right direction.

The Commission also concludes that the LCIRP of Nantahala complies with the Commission's LCIRP Rules and should be approved.

The Commission is not persuaded that CP&L and Duke should make a special study of the remaining useful lives of their combustion turbines as proposed by Empire. The utilities currently conduct depreciation studies of their facilities on approximately five-year cycles, and the studies are time-consuming and expensive. The Commission is also not persuaded that a special study of the impact of alternative generating sites on the CP&L/Duke interconnection need be made as Empire has proposed. As cited elsewhere herein, the Commission dismissed Empire's application for a certificate for its Rolling Hills project.

NCSEA and CCNC presented no witnesses, but filed a brief requesting that utilities be requhred to present to the Commission their assessment details regarding solar programs with their next LCIRP update (or short term action plan). Solar programs discussed should include passive solar space heating, active and passive solar water heating, photovoltaics, advanced glazings, daylighting, and directional orientation of structures.

NCSEA and CCNC do not contend that the utilities are failing to consider solar resources. Their desire for more detailed discussion of solar resources appears to reflect a need for reassurance that fair and appropriate consideration is being given to them. The Commission would simply note here that each utility is encouraged to consider fully any alternative energy resources or energy efficiency measures that are reasonably available to them.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 AND 10

In Ordering Paragraph 5 of its Max 17, 1990, Order Adopting Least Cost Integrated Resource Plans in Docket No. E-100, Sub 58, the Commission required each utility to file proposed plans for timely recovery of costs associated with the implementation of its approved LCIRP.

The May 17, 1990, Order reflects that this requirement resulted from the Commission's agreement with Public Staff witness Dr. Eric Hirst's recommendation that the recovery of costs associated with operating DSM programs should be considered. In addition, Dr. Hirst testified that the Commission should consider the recovery of lost revenues resulting from the operation of cost-effective energy efficiency programs and rewarding the utilities for aggressively pursuing DSM programs. The Commission indicated that it would consider further the question of financial incentives for good performance.

The Commission noted in its Order that the desire of intervenor and public witnesses that the utilities be rewarded for the implementation of their least cost plans arose from the perceived need to make the utility indifferent between the selection of a demand-side option and a supply-side option. The Commission concluded that deferral accounting procedures should be initiated for the purpose of accumulating and deferring costs associated with the implementation of Commission approved least cost planning, with the types of costs being addressed in the companies' proposed plans to be filed with their next short term action plans.

CP&L, Duke and NC Power filed proposed plans for the recovery of DSM costs and incentives during May 1991 and Nantahala filed its comments in June 1991.

Comments regarding the utilities' proposals were filed by the Public Staff and other parties in August 1991. The Public Staff commented that the Nantahala and NC Power proposals lacked sufficient detail, that the CP&L proposal was unlawful in part and unreasonable in part, and that the Duke proposal was being modified in accordance with ongoing negotiations in Duke's pending general rate case.

The Attorney General filed comments expressing a strong objection to an annual LCIRP rider and concern about incentive rates of return on investments for DSM programs where resulting reductions in utility bills are unproven.

CUCA commented that the proposals may be unlawful in part, and that the proposals involve highly favorable ratemaking treatment for DSM costs regardless of the value of the DSM programs.

CIGFUR commented that the current method of rate regulation should not be changed to enhance DSM programs. CIGFUR commented further that if any mechanism for tracking DSM costs is found to be appropriate, the utility should be required to demonstrate with relative certainty the amount of costs and that the costs are not already being covered in rates.

SELC commented that the utility proposals are only piecemeal approaches to DSM programs and that the listed programs lack goals and strategies for maximizing market penetration.

On September 9, 1991, a stipulation between Duke and the Public Staff was fildd and approved in Duke's general rate case in Docket No. E-2, Sub 487. This stipulation allows Duke to defer for future rate recovery certain DSM program costs beyond those currently reflected in the rates approved by the Commission. The following costs were identified: credits for interruptible service; credits for load control; payments for standby generation; advertising costs; and incentive payments/rebates. With respect to lost revenues, the stipulation provided that recovery of lost revenues could be sought but that the burden of proof is on the utility. It further provided that lost revenues would be offset by "found" revenues attributable to load factor improvement programs. The stipulation further provided that at the time rewards were recognized pursuant to G.S. 62-2(3a), they would be added to the deferred balance.

The Commission's April 28, 1992, Order in Docket No. E-100, Sub 64, required the Public Staff and the four electric utilities to file status reports by May 31, 1992, describing where negotiations stood between the respective utilities and the Public Staff regarding DSM cost recovery and incentive mechanism issues. The Commission further ordered that any unresolved issues regarding DSM cost recovery and incentive mechanisms that the utilities desired to pursue should be included in the public hearing on LCIRP scheduled for late 1992, in Docket No. E-100, Sub 64.

CP&L, Duke, Nantahala, NC Power and the Public Staff all filed timely status reports. These generally indicated that substantial differences remained between the Public Staff, CP&L, Nantahala and NC Power, which were not likely to be resolved prior to the LCIRP hearing. With respect to Duke, however, the status reports indicated that Duke had submitted a completely revised reward mechanism in early 1992, and that an agreement in concept had been reached, and was in the process of being reduced to writing.

Subsequent negotiations between the Public Staff and Duke resulted in a Stipulation concerning a DSM reward mechanism dated October 20, 1992, which was filed in this docket.

<u>The Duke Reward Mechanism Stipulation</u>

The reward mechanism stipulated to by Duke and the Public Staff is based on a shared savings approach, under which a portion of the savings to customers resulting from DSM programs that have been approved by the Commission in conjunction with Duke's LCIRP will be provided to Duke as a reward for DSM programs which decrease Duke's customers' utility bills. A reward can be earned for demonstrated kW and kWh savings. Rewards will be paid based on DSM accomplishments experienced after January 1, 1992. The total annual reward that can be recorded in the deferral account is 0.5% of Duke's North Carolina retail revenues recorded in the calendar year for which the reward is claimed. The details of the calculation and the amount of reward ultimately to be allowed in rates is subject to review and approval prior to a reward being included in rates.

The reward calculation can be expressed as follows:

Reward = Net savings per unit x Actual units accomplished x 15% x NC retail allocation.

The net savings are identified by the Utility Cost (UC) Test, which indicates the impact of a program on aggregate bills. If the UC Test shows that a DSM program produces a net savings, implementation of that program would result in customer bills being lower in the aggregate than they would have been without the program (i.e., lower than they would have been using the supply-side alternative). The savings are calculated using projected DSM accomplishments and economic analysis principles to determine the savings per unit of DSM in present worth terms over a 19 year planning period using a specified escalation and discount rate.

A savings per unit is calculated using the projected unit accomplishments for each program. This step distributes the total program savings over the projected units for the program life. An appropriate unit will be determined for each program. The reward process will use a unit which can be projected in the LCIRP process and verified through the program evaluation process. The selected unit will be used to determine the savings per projected unit.

The actual unit accomplishments for each program will be determined through the actual unit accomplishments for the previous year. Each year the program evaluation process will determine the actual unit accomplishments for the previous year.

Each year the reward will be recalculated for all previous years based on the most recent estimate of net savings as calculated by the UC Test for each program and de-escalated based on the specified escalation rate in the current year's LCIRP. The prior years' deferred account reward entries will be adjusted to reflect the recalculated reward amounts until the rewards are reflected in rates in a subsequent general rate case proceeding.

Because some DSM programs may be discontinued or experience design changes, the stipulation provides that the reward calculation will be based on the most recent estimate of net savings for the program. Duke agreed to work with the Public Staff regarding programs which experience significant design, cost or benefit changes on a case-specific basis. The quarterly status report on the deferral account will include any activity in the account related to rewards.

The Public Staff reserved its right to petition the Commission to modify or delete any aspect of the reward prospectively at any time. In addition, the

Public Staff took the position that its agreement with deferral accounting for DSM cannot be utilized as a basis to seek deferral accounting for other types of costs.

Because of certain philosophical differences regarding the need for and the appropriateness of on-going rewards for positive accomplishments, Duke and the Public Staff appended statements of position to the stipulation. Duke's position is that it is seeking a reward for DSM accomplishments in order to recognize that major DSM expenditures are essential to meet the future energy needs of its customers and are endorsed and encouraged by the Commission. Duke expects DSM expenditures to increase and remain a major expenditure for the foreseeable future. Therefore, a mechanism is necessary to place DSM expenditures on a similar footing with supply-side capital investments. Duke believes the proposed reward mechanism provides one method. Duke believes that approval of its reward mechanism will establish that the Commission encourages the increased use of DSM as a resource to meet future energy and capacity needs.

The statement of position of the Public Staff provided that special ratemaking treatment of DSM currently is appropriate to encourage utilities to aggressively invest in DSM resources. This special treatment includes three key elements: (1) the recovery of certain incurred costs associated with operating DSM programs; (2) the recovery of "lost" revenues resulting from energy efficiency programs; and (3) an additional financial incentive, or reward, for exemplary DSM accomplishments. The stipulated deferred account mechanism contemplates the potential inclusion of all three of these elements.

The Public Staff contended that the use of deferred accounting in the past has been in unique situations and is generally not appropriate for on-going costs. However, because of the policy of encouraging DSL expressed in G.S. 62-2(3a), including the consideration of appropriate rewards for DSM which decrease utility bills, the Public Staff has agreed to deferred accounting for all three of the identified special ratemaking elements.

The statement of position further indicated that the Public Staff strongly believes that the electric utilities have an obligation to pursue DSM when it is the least cost option regardless of any potential special ratemaking treatment. The Public Staff has agreed to the stipulated deferred accounting in an effort to remove any utility perceived disincentive to the implementation of DSM programs.

With respect to the third element, the additional financial incentive or reward, the Public Staff contended that the majority of states that have included this element have included it explicitly and solely as a "jump start" to prompt utilities to begin the more active consideration of DSM as a resource option. Wisconsin, for example, already has begun the elimination of the reward element of its special treatment of DSM. The Public Staff ended its statement by expressing its strong belief that the reward element should be allowed exclusively as a "jump start" and should be discontinued as soon as is reasonably practicable.

<u>CP&L and NC Power Stipulations</u>

NC Power proposed a revised DSM cost recovery and incentive mechanism to the Public Staff on August 27, 1992. After multiple discussions, an agreement in principle was reached, causing NC Power to request an extension of time for the prefiling of testimony. A stipulation and the testimony of Mary C. Doswell on the outstanding issue of the proper period over which the bonus or reward should be calculated were filed on October 20, 1992. The Public Staff and NC Power agreed that the deferral of costs should commence with the effective date of the rates resulting from NC Power's rate case in Docket No. E-22, Sub 333.

As set out in the stipulations, the proposed bonus mechanism will require NC Power to submit annual target penetration levels and corresponding annual cost savings per unit of penetration for each DSM program subject to the bonus reward calculation. For a given year, the estimated maximum reward payout will be the North Carolina jurisdictional portion of 15% of the product of the target penetration level and the estimated savings per unit of penetration. The savings per unit of penetration is calculated by distributing the total utility cost (UC) test net savings over the planning horizon in such a way that the annual savings per unit of penetration escalates at a rate equal to the assumed rate of inflation. The net present value of the maximum reward, assuming complete success in achieving the annual penetration targets, will equal 15% of the original total utility cost test net savings over the planning horizon.

NC Power will annually validate the actual DSM program results achieved for the prior year and will re-estimate the penetration targets and the associated savings per unit of penetration for subsequent years. For deferral purposes, the reward earned will be a product of the validated actual penetration levels and the approved estimate of savings per unit of penetration for subsequent years.

Following the Commission's Order dated September 22, 1992, granting CP&L's motion to delay the filing of its testimony, CP&L and the Public Staff engaged in extensive negotiations. On October 20, 1992, the Commission granted CP&L until October 30, 1992, to file testimony. On October 20, 1992, CP&L and the Public Staff reached an agreement in principle on a DSM mechanism that includes three key elements: DSM program cost deferral, lost revenues, and an additional financial incentive bonus. A stipulation and the testimony of David R. Nevil were filed on October 30, 1992.

Because of time constraints, the CP&L stipulation provides that further discussions are required before the parties can agree upon the appropriate methodology for calculating the net unit savings for CP&L's DSM programs. The Public Staff and CP&L agreed that the appropriate methodology would be similar to the methodologies utilized by Duke and NC Power and will yield results consistent with the results produced by those methodologies. The stipulation further provided that the credit for ratepayers for DSM costs already being recovered from ratepayers will be based on a reasonably current b'se year and the precise formula will be subject to further stipulation.

Witness Nevil's testimony requested that a longer period of savings be used to calculate CP&L's bonus and that a separate cost recovery and reward mechanism be approved for purchases from qualifying facilities (QFs) and other long-term power purchases (i.e., a supply-side cost recovery and incentive mechanism).

The stipulations entered into by the Public Staff with CP&L and NC Power, respectively, are virtually identical to the cost recovery stipulation of

September 1991 and the reward mechanism stipulation of October 1992 entered into between the Public Staff and Duke, with the exception of the number of years of net savings used to calculate the reward and the "end effects".

Number of years and "end effects"

NC Power proposes that the computation of the annual savings per unit of penetration (units accomplished) be based on 29 years of UC test net program benefits plus the net savings from the end-effects period, which extends indefinitely into the future. CP&L proposes that 25 years be used to calculate the net savings. The Public Staff's position is that a maximum of 19 years of the UC test net savings should be used to calculate the reward and that end effects should be excluded.

NC Power witness Doswell testified that NC Power's position rests principally on two arguments. First, using 29 years plus the end-effects period is entirely consistent with the Company's generation expansion planning and DSM program evaluation horizon used in the development of its LCIRP. She testified that there should be no distinction between the program savings implicit in the Company's LCIRP and those recognized in the bonus mechanism. Secondly, a 29 year planning horizon with end effects is necessary to capture the long-run nature of most program benefits. Witness Doswell further testified these issues were important because their resolution would directly affect the level of the reward that can be earned by the Company under the mechanism.

CP&L witness Nevil's testimony was similar. He testified that using a 25-year period was entirely consistent with the Company's DSM program evaluation horizon used in the development of its LCIRP and that there should be no distinction between the program savings implicit in the LCIRP and those recognized in the reward mechanism. In addition, he testified that a 25-year planning horizon is necessary to capture the long-run nature of most program benefits.

Public Staff witness Maness testified that the Public Staff's position supporting 19 years as the maximum number of years that should be used resulted from its extensive and detailed negotiations with Duke regarding the reward calculation methodology. He testified that obviously the further into the future one projects savings, the less certain and precise those projections become. To encourage the utilities to actively pursue DSM, however, rewards would be paid concurrently with the implementation of the DSM measures rather than waiting until the savings are actually realized. The Public Staff thus became concerned that reward payments locked in and/or paid over the early years of a DSM program could be significantly impacted by inaccurate projections of long-term future net savings. This concern was highlighted in the examples of the bonus calculation provided to the Public Staff by Duke during negotiations, in which the majority of savings projected to be produced by each program were realized in the end-effects period subsequent to the initial 19-year horizon.

Witness Maness further testified that as a result of the Public Staff's concerns it reached a "package deal" settlement with Duke that included a 19-year limit on the net savings included in the calculation, a bonus percentage of 15%, an overall cap of 0.5% of annual recorded North Carolina retail revenues, and an annual true up based on refined savings estimates as verified by acceptable evaluation procedures. With regard to the bonus calculation methodologies of

CP&L and NC Power, the Public Staff was opposed to the extension of the 19-year limitation without a corresponding change in at least one of the other provisions (e.g., a lowering of the reward percentage) because it would be unfair to allow CP&L and NC Power to utilize a less restrictive set of constraints than those agreed to by Duke.

Witness Maness testified that the differences among the utilities did not necessitate their rewards being calculated differently, and that Duke initially included end effects before agreeing to a 19-year period. He testified that the stipulation the Public Staff achieved with Duke was a balance that should produce a reasonable reward, and that the balance would be upset if the Commission did not adopt the same period of years for CP&L and NC Power.

Witness Maness reiterated the Public Staff's position that the reward part of the incentives was a "jump start" to get the companies over the initial hurdle and involved in DSM. He also testified that the Public Staff considered all of the special accounting provisions to be temporary, with the reward being "the most temporary of the temporary."

In response to cross-examination by the Attorney General, the Public Staff's consultants testified that financial incentives should be used if necessary, but are not a preferred course. They agreed that there are good economic reasons for pursuing DSM, among which were avoiding the risks of construction, such as getting necessary permits, cost overruns, rate shock, intervenor prudency audits and consumer unhappiness.

<u>Other testimony</u>

SELC witness Chernick testified that appropriate DSM activity should receive the easiest, most rewarding and least painful regulatory treatment of any resource acquisition option. Conversely, he said resource plans that do not fully utilize DSM should be more difficult and less rewarding for the utility and its shareholders. He further testified that if DSM were like other utility activities, a special mechanism would be unnecessary. He said the Commission should consider the disincentives embedded in traditional cost-recovery practices which assume more kilowatt hours will be sold and more plants built. He further testified that most of the aspects of DSM that justify special ratemaking treatment will likely be temporary. He contended that in the longer term, DSM will be embedded in corporate culture, regulatory practices, historical rates and customer expectations.

Witness Chernick emphasized that special cost recovery mechanisms should be extended only to energy efficiency programs. He said that utilities have generally needed no special mechanisms for promotional load management and rate design programs or for supply-side efficiency improvements. The Commission should exclude incentives for actions utilities have taken and will continue to take without special encouragement.

Witness Chernick recommended that the incentive mechanism reflect utility performance. He said incentives should increase if the utility does a better job, that is, if more kWh or more valuable kWh are saved or the cost of DSM is reduced for the same savings. Incentives should be offered only for superior performance. They should be structured as shared savings above some threshold and they should be phased out once DSM is a routine portion of utility planning and the normal regulatory mechanism can work. He contended that inadequate or counterproductive DSM actions should result in penalties, such as reductions in allowed return on equity, rejection of proposals to acquire new supply side resources and even disallowance of avoidable supply costs, such as fuel, new transmission and distribution equipment and new generation.

Witness Chernick further testified that the measure of net savings should be changed from the UC Test to the Total Resource Cost Test (TRC), that a threshold should be created below which no incentive would be paid, and that monitoring and evaluation should be used to ensure that incentives are paid only for actual results.

With respect to the proper time period to be used to calculate the rewards, witness Chernick testified that the disagreement appeared to be "a tempest in a teapot." He believed that the major difference between the parties appeared to be NC Power's failure to properly discount future cash flows and that NC Power's concerns with end effects appeared to arise from its incorrect treatment of avoided fixed costs.

Witness Chernick concluded his testimony by recommending that CP&L and NC Power not be eligible for any incentives because he contended that their DSM portfolios are wholly inadequate.

CIGFUR witness Phillips testified in opposition to the joint stipulations, using CP&L's to illustrate his concerns. He testified that G.S. 62-2(3a) did not appear to authorize the deferral of costs or the recovery of lost revenues. If allowed, he stated that a general rate case should be required prior to any deferrals and special cost recovery mechanisms. He further testified that no utility should receive a reward for performing its management obligations; and he said if rewards are offered they should be of limited amount and only available for a limited amount of time.

<u>Conclusions</u>

The Commission concludes that special ratemaking treatment of DSM currently is appropriate to encourage utilities to invest aggressively in DSM resources. This special treatment includes three key elements: (1) the recovery of certain incurred costs associated with operating DSM programs; (2) the recovery of "lost" revenues resulting from energy efficiency programs; and (3) an additional financial incentive, or reward, for exemplary DSM accomplishments.

The deferred account mechanism stipulated to between the Public Staff and Duke, NC Power and CP&L, respectively, contemplates the potential inclusion of all three of the elements identified above. The use of deferred accounting for all three of the special ratemaking elements is appropriate. The purpose of the stipulated deferred accounting is to attempt to remove any perceived disincentive by utilities to the implementation of DSM programs.

With respect to the DSM cost recovery and lost revenues portions of the stipulations, the Commission notes that Duke's DSM cost recovery and lost revenues stipulation was approved in its last general rate case, Docket No. E-7, Sub 487, and that the cost recovery and lost revenues portions of the stipulations between the Public Staff and NC Power and CP&L, respectively, are virtually identical to the Duke stipulation. The Commission concludes that the cost recovery and lost revenues portions of NC Power's and CP&L's stipulations should be approved. NC Power's deferral of costs should commence with the effective date of the Commission's rate case Order in Docket No. E-22, Sub 333. CP&L's deferral should commence with the effective date of a future Order approving the further stipulation needed to establish the level of costs in current rates.

With respect to the third element, the additional financial incentive or reward mechanism, the Commission cannot conclude at this time, as advocated by the Public Staff, that the reward element should be allowed exclusively as a "jump start" mechanism and should be discontinued as soon as is reasonably practicable. Nevertheless, the need for continuation of the reward mechanism is an issue that the parties may address in future LCIRP proceedings. The Public Staff, and any other party for that matter, always has the right to petition the Commission to prospectively modify or delete any aspect of the reward mechanism. That being the case, the Commission concludes that the stipulation between the Public Staff and Duke is reasonable. The only area of disagreement between the Public Staff and NC Power and CP&L, respectively, is the number of years to use in the calculation.

NC Power has proposed that the computation of the annual savings per unit of penetration (units accomplished) be based on 29 years of UC test net program benefits plus the net savings from the end-effects period. CP&L proposed that 25 years be used to calculate the net savings. The Public Staff's position is that a maximum of 19 years of the UC test net savings should be used to calculate the bonus and that end effects should be excluded.

The Commission concludes that all three utilities should be treated consistently for purposes of the reward calculation. Public Staff witness Maness testified that the Public Staff and Duke engaged in extensive and detailed negotiations resulting in an agreement. Witness Maness further testified that the Public Staff "went as far as we felt we could go" in reaching the agreement. The Commission believes that the one-on-one extensive and detailed negotiations between the Public Staff and Duke provides a firm foundation for a conclusion that the methodology eventually agreed to is a reasonable one. The "package deal" settlement reached between the Public Staff and Duke includes a 19-year limit on the net savings included in the calculation, a reward percentage of 15%, an overall cap of 0.5% of annual recorded North Carolina retail revenues, and an annual true-up based on refined savings estimates as verified by acceptable evaluation procedures. Extending the 19-year limitation for CP&L and NC Power without a corresponding change in at least one of the other provisions (e.g., a lowering of the reward percentage) would be unfair because their reward would be calculated using a less restrictive set of constraints.

For Duke, the reward should apply to accomplishments beginning January 1, 1992, as provided for in the stipulation. For NC Power, the reward should apply to accomplishments beginning January 1, 1993. The effective date for CP&L's reward will be established be a later Order following the filing of the contemplated stipulation on the methodology for calculating the net unit savings for CP&L's DSM programs.

CIGFUR's general opposition to any cost deferral or incentive mechanism associated with DSM programs was previously addressed during the course of earlier proceedings in Docket No. E-100, Sub 58. Specifically the evidence and conclusions for Finding of Fact No. 11 in the Commission's May 17, 1990, Order Adopting Least Cost Integrated Resource Plans noted that "all intervenor witnesses and public witnesses indicated their desire that utilities be rewarded for implementation of their least cost integrated resource plans" and that "there is a general consensus by all parties that procedures must be developed to encourage positive least cost integrated resource planning accomplishments." The Commission concluded that each utility should therefore file a proposed plan for recovery of LCIRP costs. The issue before the Commission in Docket No. E-100, Sub 64, is simply <u>which</u> cost recovery proposal should be implemented for each utility.

The Commission's authority for the establishment of a cost deferral and reward mechanism is found generally in G.S. 62-133, which requires the Commission to consider all material facts and to rely upon those ratemaking mechanisms necessary to the establishment of fair and reasonable rates. Furthermore, the General Assembly enacted G.S. 62-2(3a), effective June 12, 1987, which imposes a <u>duty</u> upon the Commission to consider incentives, rewards and other ratemaking approaches. Specifically, the Commission has been directed as follows:

> To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, <u>including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills.</u> (emphasis added)

The General Assembly obviously enacted G.S. 62-2(3a) in contemplation of a ratemaking scheme, including incentives, which serves to promote utility efficiency and conservation with the stated purpose of decreasing utility bills.

The Commission is required by G.S. 62-2(3a) and 62-133 to fix rates in a manner which results in the least cost mix of generation and demand-reduction measures that is achievable. The cost recovery and incentive mechanisms included in the stipulations are designed to achieve that goal. In summary, the stipulated cost recovery and reward mechanisms are consistent with the Public Utilities Act and are within the Commission's authority to approve.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence regarding the special cost recovery mechanisms for supply-side expenditures proposed by CP&L and Allied Signal is in the testimony of CP&L witness Nevil, Allied Signal witness Plett and Public Staff witness Maness.

<u>CP&L's Proposal</u>

CP&L witness Nevil recommended that the Commission approve a cost recovery mechanism for supply-side options such as purchases from qualifying facilities (QFs) and other long-term power purchases. Witness Nevil preferred an annual rider but he also found a deferral accounting mechanism to be acceptable. He testified that the supply-side mechanism should include both cost recovery and a reward to the shareholders to recognize the risks faced in selecting the least cost option. In general, witness Nevil argued that a supply-side cost recovery mechanism is appropriate because the incremental increases in purchases from QFs and other non-CP&L suppliers may not be large enough to prompt thd filing of a general rate case, and, in the interim, the utility and its shareholders are not compensated for these expenditures. In witness Nevil's view, the absence of a supply-side cost recovery mechanism causes a disincentive to least cost planning and an inequitable sharing of costs and benefits between the shareholders and the ratepayers.

Public Staff witness Maness testified that the Public Staff opposes the adoption of any cost recovery or reward mechanism for supply-side expenditures. The Public Staff disagrees with witness Nevil's assertion that in the interim between general rate cases, the utility and its shareholders are by definition not compensated for their additional expenditures. He contended that additional expenditures in a given area may be offset by increased revenue due to customer growth or by decreased expenditures in another area. Cost recovery mechanisms for DSM resources are being considered at least in part because these resources may not enhance, and in some cases may reduce, the utility's revenue base. However, increases in supply-side resources are in many cases directly related to increases in the customers' demand for electricity. Thus, increases in supply-side expenditures are much more likely to be matched at least partially by increases in revenue than are increases in DSM expenditures. Therefore, the Public Staff continues to believe that changes in rates set to recover non-fuel supply-side costs should be made only in general rate cases where the net effect of <u>all</u> changes in revenue and costs can be taken into account.

The Public Staff also disagrees with witness Nevil's recommendation that the shareholder be rewarded for the risks faced in selecting the least cost supply-side option. Witness Maness contended that the utility has a duty to pursue the least cost option, regardless of the ratemaking treatment applied to its expenditures. Under the ratemaking process in North Carolina, shareholders are compensated for their capital investment in the Company. If an additional supply-side option does not require a capital investment, no additional return need be paid to the shareholders.

<u>Allied Signal's Proposal</u>

Frederick R. Plett, a Regulatory Affairs Specialist with Allied-Signal Inc., Metglas Products, testified on behalf of his employer, which is a manufacturer of amorphous metal for electric utility transformers. The purpose of his testimony was to communicate the potential benefits of greater transmission and distribution (T&D) efficiency and discuss the regulatory barriers he perceived that could be impeding the North Carolina utilities from more fully exploiting these opportunities.

He discussed a number of perceived barriers, both economic and non-economic. The economic barrier he perceived was the utilities' requirement that high efficiency transformers must be cost effective over the life of the investment, meaning that the present value of future energy and capacity savings must outweigh the purchase price premium. He did not consider this test to be appropriate.

Other potential barriers perceived by witness Plett included regulatory l'g, returns on investment set at levels no higher than that needed just to compensate the use of capital, budgetary constraints, enthusiasm for customer conservation, inappropriate planning time horizons, inconsistent evaluations, concerns about potential disallowances, internal organizational barriers, and lack of awareness.

He recommended that the Commission strive to remove or mitigate barriers that can inhibit utilities from making cost effective investments in T&D efficiency. He requested the Commission to state explicitly that any incentive or cost recovery mechanism developed in this docket for DSM programs shall also include cost-effective utility T&D efficiency investments in the future. He further requested that the Commission encourage the utilities to specifically consider these programs in their LCIRP filings and on a basis consistent with all other supply- and demand-related programs.

Witness Plett further testified that G.S. 62-2(3a) provided legislative support for his testimony, and that Commission Rule R8-58(a)(2), (d) and (f) supplied regulatory support. In addition, he cited a section of the new Energy Policy Act of 1992 in support of his requests.

<u>Conclusions</u>

At the outset the Commission must determine whether or not it has the authority to establish a supply-side cost recovery or incentive mechanism for purchased power and T&D investments, as requested by CP&L and Allied Signal, respectively.

The legal issues presented by these proposals are similar to NC Power's request in its 1990 rate case (Docket No. E-22, Sub 314) for an annual non-utility generation rider. The Commission concluded in that proceeding that an annual adjustment of that type outside of a general rate case was not authorized under current North Carolina law.

The various fuel clause statutes are the statutory authority for the recovery of fuel costs outside of the scope of a general rate case. The annual fuel clause proceeding currently being used by the Commission is specifically provided for in G.S. 62-133.2. It explicitly excludes any purchased power costs other than the fuel portion.

Prior to the amendment of G.S. 62-133.2 to allow for an experience modification factor, the North Carolina Court of Appeals in <u>State ex rel. Utilities Commission v. Thornburg,</u> 84 N.C.App. 482, 353 S.E.2d 413 (1987), <u>cert. denied,</u> 320 N.C. 517, 358 S.E.2d 533 (1987), held that the Commission's use of such a factor to allow CP&L to recover a past underrecovery of fuel costs was in excess of the Commission's statutory jurisdiction. Given this holding, it seems likely that an adjustment to base rates outside of a fuel clause proceeding or outside of a general rate case in order to allow the recovery of non-fuel purchased power costs and T&D investments may be illegal.

The Commission's past use of riders and "true-ups", such as the Curtailment Tracking Rate (CTR) approved by this Commission in 1975 for North Carolina Natural Gas Corporation and the Volume Variation Adjustment Factor (VVAF) approved in 1976 for Public Service Company of North Carolina were premised on circumstances which appear to be dissimilar to the facts of this case. The CTR and VVAF were approved because of the curtailment of natural gas supply by what was then the Federal Power Commission (FPC) because of shortages of regulated natural gas. The specific level of curtailment for each natural gas utility depended upon which curtailment plan the FPC approved, which was then subject to change by the FPC. Because of this dilemma, the Commission approved an estimated rate premised on projected gas availability, which was then corrected for actual gas availability. Unlike the natural gas utilities, which had no control over the volumes (or the cost) of natural gas they would receive at the time the "true-ups" were approved and therefore no control over the revenues or expenses resulting from the volumes received, the electric utilities have substantial control over their purchases of power and T&D investments.

Another situation that can be compared to the requests in this case is the purchase power adjustment clause the Commission has implemented for Nantahala. The Commission has allowed Nantahala outside of a general rate case to pass through changes in utility wholesale rates approved by the Federal Energy Regulatory Commission (FERC). The United States Supreme Court has made it clear that the Federal Power Act grants the FERC exclusive jurisdiction over wholesale utility rates and that once the FERC sets such a rate a State may not conclude in setting retail rates that the wholesale utility rates are unreasonable. Nantahala Power & Light Company v. Thornburg, 476 U.S. 953 (1986). Therefore, Nantahala's purchase power adjustment clause is not the same as a supply-side cost recovery mechanism herein because it addresses costs mandated by the FERC rather than costs at the discretion of the utility.

Under North Carolina law, changes in electric rates to recover non-fuel supply-side costs are normally made within the context of a general rate case where the net effect of all changes in revenue and costs can be taken into account. In between general rate cases, additional expenditures in a given area may be offset by increased revenue due to customer growth or by decreased expenditures in another area. Increases in supply-side resources are in many cases directly related to increases in the customer's demand for electricity. Thus, increases in supply-side expenditures are much more likely to be matched at least partially by increases in revenues than are increases in DSM expenditures.

General Statute 62-2(3a) declares the following to be the policy of the State:

(3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills.

Webster's Third New International Dictionary defines "demand" as the need or request for a commodity; as opposed to supply. Demand-side programs are generally defined as programs that are undertaken for the purpose of increasing a customer's energy efficiency, reducing its consumption of electricity (on peak or off), or improving its load factor.

Consideration of available purchased power and T&D efficiency options are a necessary and indeed required part of least cost planning, but they are not demand-side options. Thus, the express terms of G.S. 62-2(3a) dictate a conclusion that they are not included within its scope.

Witness Plett cites the Energy Policy Act of 1992, which was signed into law by President Bush on October 24, 1992, as support for his proposal. While this Act is new and will require further study and consideration, nothing in the Act appears to require this Commission to adopt a cost recovery/incentive mechanism that is outside the scope of North Carolina law.

The Commission will fully consider the provisions of the Act and their implications in the future as least cost planning further evolves, but concludes that there is nothing in the Act that compels the Commission to approve special ratemaking treatment for purchased power or T&D investments in this proceeding.

Accordingly, the Commission concludes that CP&L's and Allied Signal's proposals for special cost recovery/incentive mechanisms for supply-side expenditures should not be approved herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 AND 13

The evidence for these findings of fact is found in the supplemental testimony of CP&L witness Montague, Duke witness Denton, NC Power witnesses Ross and Jones, Nantahala witness Tucker, Empire witness Greenberg and Public Staff witness Powell.

Empire filed a Motion to Further Define Commission Rule R8-58(e) and the Evaluation Process for Non-Utility Generation Proposals on June 30, 1992. On August 19, 1992, the Commission issued an Order Requiring Prefiled Testimony in which it required all parties of record to prefile testimony within 30 days addressing the issues of: (1) the interpretation and/or clarification of Commission Rule R8-58(e) and (2) the need for and/or the terms of an appropriate evaluation process by which utilities should assess future non-utility purchased power proposals.

Direct testimony was submitted pursuant to the Commission's August 19, 1992, Order regarding Rule R8-58(e) by Empire, NC Power, Duke, CP&L, Nantahala and the Public Staff in September 1992.

Rule R8-58(e) requires that "each utility shall assess on an ongoing basis the potential benefits of <u>reasonably available</u> purchased power resources. The assessments shall include costs, benefits, risks, uncertainties, and reliability where appropriate. The utility shall discuss its overall assessment of its purchased power resources; including but not limited to purchases from cogenerators, small power producers, independent power producers and other utilities, and provide details of the methods and assumptions used in the assessment of those purchased power resources <u>having a significant impact</u> on its least cost integrated resource plan". (emphasis added)

CP&L witness Montague testified that Rule R8-58(e) does not need to be changed. The language of the rule is intended to provide a flexible framework within which utilities may develop plans for the future. He said that flexibility in the planning process is also important to limit the scope of the LCIRP within reasonable bounds. In the experience of CP&L the existing rule has provided a suitable framework for the evaluation of numerous proposals from non-utility generators and the selection of several of these proposals.

Witness Montague pointed out that the language of the rule requires that utilities assess the potential benefits of "reasonably available purchased power resources." In addition, the rule requires that a utility "provide details of the methods and assumptions used in the assessment of those purchased power resources having a significant impact on its least cost integrated resource plan." He contended that the Commission intended for the rule to provide flexibility and cited the Order of the Commission in which the rule was adopted as stating that the rules "provided a framework wherein least cost considerations, environmental concerns, operating needs, and flexible response to future unknowns can all be accommodated." He testified that the choice of the qualifier "reasonably available" recognizes the utilities' need to avoid the expense of preparing detailed evaluations on clearly infeasible options. Similarly, the qualifier "having a significant impact" was included to hold the reporting requirements to within manageable limits and to keep the report focused on the significant components of the plan.

Witness Montague also testified that CP&L has considered numerous proposals from non-utility generators under the existing rules. CP&L presently purchases approximately 461 megawatts of power from 37 non-utility generating plants and has agreements to purchase another 650 megawatts from other utilities. He contended that CP&L is not biased in its evaluations of proposals from other utilities and from non-utilities and supports the propriety of the flexibility designed into Rule R8-58(e) by the Commission.

CP&L witness Montague testified that the LCIRP process makes no distinction for evaluation of purchased power options. It provides for a consistent and balanced view of the resource options available. He contended that Empire wants to establish a separate evaluation process specifically for non-utility generators, and that such a process could be rigid and possibly inconsistent with the evaluation of other resource options.

Witness Montague explained that CP&L receives a wide variety of non-utility purchased power proposals. Some are more feasible than others. Discussions with the proposer can sometimes reveal that the proposal is clearly not economical for the Company and its ratepayers and go no further than this. In these situations, it would be inefficient to be required to follow a prescribed process and perform detailed analyses.

Witness Montague also said that the present language of Rule R8-58(e) properly recognizes that some non-utility purchased power proposals require more extensive analysis than others and that no single, rigid rule can distinguish those proposals that merit full evaluation from those that do not. He said some proposals are submitted to CP&L on a confidential basis. If a rigid evaluation procedure were to require the publication of certain proposals, some cost-effective proposals might never be offered. Thus, a requirement to apply some mandated process which carries with it fixed reporting requirements could work to the detriment of all parties.

Witness Montague pointed out that the Commission's Rules provide for an adequate remedy where a utility's assessment procedures are challenged. Under the rules, an "aggrieved party can intervene in the utility's next LCIRP proceeding or file a complaint as Empire did with Duke Power."

Duke witness Denton stated that Rule R8-58(e) generally requires that utilities include consideration of purchased power resources along with supply-side and demand-side resource options in determining its LCIRP. Rule R8-58(e) also requires each utility to include in its LCIRP a general discussion of the utility's overall assessment of its existing and potential purchased power resources. The Rule further requires that the utility discuss its rationale for including a particular purchased power resource in its LCIRP, including a discussion of the methods and assumptions used in the assessment of the resource.

Witness Denton testified that in determining whether a purchased power proposal of a non-utility generation facility represents a "reasonably available" resource, the utility must consider the risks, uncertainties, and expected reliability of the resource relative to other resource options. The utility must have the same level of confidence that the purchased resource will be as available, reliable, and cost effective as other demand-side, supply-side and purchased power resource options. This is particularly important for non-utility generators because their proposals are typically for facilities which have not yet been built. He further testified that a purchased power resource has a "significant impact" on Duke's LCIRP if it causes a change in the plan or is explicitly included in the plan.

Duke witness Denton testified that Duke's compliance with Rule R8-58(e) is demonstrated in its 1992 LCIRP. Duke receives numerous contacts from other utilities, cogenerators and small power producers, which are qualifying facilities (QFs) under PURPA, and from independent power producers (IPPs). Duke negotiates a contract with QFs smaller than 80 MW as required by PURPA under Commission-approved standard rates and contract terms. Purchased resource proposals from QFs larger than 80 MW or from IPPs or other utilities are evaluated on a case-by-case basis as they are received, taking into consideration the availability, costs, benefits, risks, uncertainty and reliability of the proposed resource relative to other resource options.

A discussion of Duke's overall assessment of its purchased power resources is included in Duke's 1992 LCIRP. It includes a diagram of Duke's present Purchased Resource Economic Evaluation Process. Witness Denton testified that Duke also files its Cogeneration and Small Power Production Status Report each year in Docket No. E-100, Sub 41, which now includes more detail on both contacts and executed contracts and information on the status of activity involving IPPs. Duke has an individual assigned to handle its non-utility generation activities and provide information to the Commission, Public Staff and other interested parties. Duke is also required to file with the Commission any negotiated purchased power agreements.

Witness Denton testified that Duke's LCIRP includes 493 MW of firm purchased capacity. Fifty-five (55) MW of this capacity is from non-utility generators. Duke currently has contracts with 32 non-utility generators, all QFs.

Witness Denton testified that Duke is currently developing a competitive bidding process and a request for proposals which can be utilized for future capacity needs. Duke anticipates that the competitive procurement process will include a solicitation and evaluation of capacity offered by QFs, IPPs, and other utilities. Duke is also developing a more detailed evaluation process for IPPs.

Witness Denton testified that the current rule effectively provides the opportunity for each utility to address the specific and unique conditions it faces and therefore does not need revision or clarification. Witness Denton also testified that there is no need for a generic or utility-specific process by which utilities should evaluate future non-utility purchased power proposals; that the business conditions facing each of the utilities are unique and dynamic; that there is substantial variety among types of non-utility generation that might be proposed to a particular utility; and that Duke already has in place a process to evaluate purchased power proposals.

NC Power witness Ross testified that NC Power currently complies with the filing requirements of Rule R8-58(e), that the rule is clear and unambiguous and that further clarification or interpretation of that rule is unnecessary. The Company also submitted rebuttal testimony of Jeffrey L. Jones, who testified in response to the proposals of Empire and the Public Staff. Witness Jones discussed the unique characteristics of the Company's competitive bid solicitation process for NUG proposals. He also asserted that the Commission should distinguish, in any future rulings or generic rulemakings, between the evaluation of bids in the context of a competitive bid solicitation and the case by case evaluation of non-competitive NUG bid submissions, in order to maintain the integrity of the competitive bid solicitation process.

NC Power contended that Empire's current proposal fails to contemplate the unique characteristics of NC Power's competitive bid process. It warned that the application of Empire's proposed filing requirements would compromise the integrity of NC Power's competitive bid evaluation process as a viable tool in evaluating and acquiring NUG resources. For instance, NC Power witness Jones and Public Staff witness Powell concur that the advance publication of a target bid price would likely result in competitive bids aggregating around the target bid rather than the true (often lower) cost of certain bidders, to the detriment of ratepayers who will ultimately bear those additional costs.

Public Staff Witness Powell testified that the tender of an unsolicited proposal to a utility absent an evaluation process places all parties in an awkward situation. The utility remains vulnerable to a lengthy complaint proceeding, and the IPP has no standard by which to judge its proposal. Witness Powell maintained that the Commission would never be aware of a proposed project absent a filed complaint.

Witness Powell testified that general qualitative guidelines could be established independent of utility-specific characteristics without damaging the utility's authority to exercise its own business judgment in resource planning. He proposed that each utility file a two-step evaluation process for assessment of non-utility purchased power proposals: (1) a general proposal screening, and

(2) a detailed final evaluation. Witness Powell also proposed that the utility's filing include certain specific information concerning the criteria for proposals and evaluations.

Witness Powell disagreed with Empire witness Greenberg's assertion that there is a problem with case-by-case evaluation. Witness Powell testified that a utility must retain flexibility because system resource needs differ through time. He also testified that the cost window proposed by witness Greenberg is inappropriate because cost is not the only relevant item, and that such a criteria is too simplistic. Witness Powell also disagreed that sharing of the utility's plans and costs is appropriate, as suggested by witness Greenberg, and noted that a utility's proprietary concerns include specific details of construction plans and costs. Witness Powell said that price knowledge creates an unfair advantage in a competitive market, and that a bid made with price knowledge is not likely to represent the lowest cost project to a utility.

Empire witness Greenberg testified that Empire believes that a sharing of a utility's plans and costs coupled with a fair, established system for evaluating non-utility generator (NUG) proposals will encourage more cost-effective opportunities for NUGs to make the investment necessary for submitting unsolicited proposals. Witness Greenberg testified that a utility should be required to report its evaluation results, methods, and assumptions to the Commission in order to ensure a fair evaluation of a proposal under Rule R8-58(e). He proposed that the "significant impact" standard include a size standard or a percentage difference in cost standard (for example, 25%) which would apply to the offeror's proposal as proposed and not to a utility's analysis or adjustment thereof.

Witness Greenberg testified that the use of complaint proceedings is not sufficient to ensure a utility's compliance with Commission Rule R8-58(e). He explained how the time involved in prosecuting a complaint actually provides the utility with a window of time in which to proceed with its own supply-side project, and a window of time during which the offeror receives no relief from the Commission. He also testified that a complaint proceeding shifts the burden of proof from the utility, which would have to show its compliance with Rule R8-58(e) in a least cost proceeding or a certificate proceeding, to the purchased power offeror, who would have to show the utility's non-compliance in a complaint proceeding. He testified that this shift in the burden or proof is significant with respect to the benefits of Rule R8-58(e) for the ratepayers.

Wayne S. Leary, principal consultant for Leary's Consultative Service and president of Peat Energy, Inc. (PEI), and independent power project developer, filed testimony and appeared on his own behalf to encourage the Commission to adopt rules requiring the utilities to utilize competitive bidding for capacity and energy as part of their LCIRPs. He filed supplemental testimony which included suggested price and non-price factors for evaluating electric generation capacity. Witness Leary testified that each utility should have a Commission-approved competitive system to acquire energy and that those utilities which elect to acquire capacity through a request for proposals should have prior Commission approval of their bid program. He further testified that the Commission and the utilities should establish guidelines for negotiating and contracting to purchase capacity outside of formal bid processes. He stated that all parties expressing an interest in supplying capacity to the utility should have an opportunity to supply capacity. Witness Leary testified that a single system for competitive bidding for capacity for all utilities would not be appropriate.

The Commission concludes that it should seek to establish certain guidelines for utility evaluations of purchased power proposals by NUGs. If a utility rejects an unsolicited NUG proposal, the NUG may initiate a lengthy complaint proceeding in order to determine if it has been treated fairly. Currently, there are no established guidelines by which to judge whether the utility has acted in good faith or not.

Nevertheless, prior to establishing a set of guidelines in this proceeding, the Commission will seek more comment and input from the parties concerning specific terms that might be included in any guidelines. The utilities' testimony in this proceeding focused on the need for an evaluation process and gave little or no attention to the specific terms of such an evaluation process. On the other hand, the Public Staff provided substantial detail for its recommendation that evaluation standards be established. There was insufficient discussion of the Public Staff's proposed terms by the other parties, however.

The Commission further concludes it should not attempt to clarify or revise Rule R8-58(e) until such time as the issue of guidelines for evaluation of purchased power proposals has been fully addressed. The Commission notes that some NUG proposals are already being reported with the annual reports of QF activity in Docket No. E-100, Sub 41 by mutual agreement between the Public Staff and the utilities. However, the Public Staff wants NUG proposals to be reported in the LCIRP docket (in the STAP), and it wants the reporting to contain certain details not now available in the reports of QF activity. Empire wants the reporting of each NUG proposal to be sure it was dealt with in good faith.

The Commission is of the opinion that an appropriate set of guidelines on which to base comments and/or proposed revisions would be the following, which is based primarily on the specific terms recommended by the Public Staff.

Proposed Guidelines for Evaluation of Unsolicited NUG Proposals

There should be a two step evaluation process for NUG proposals: (1) an initial screening of all proposals; and (2) a detailed evaluation of those proposals passing the initial screening.

The evaluation process should include the reporting of specific information for each NUG proposal in the utilities' LCIRP (or short term action plan) as follows:

NUG Category (Cogen, SPP, IPP, etc.)
Facility Type (CT, Comb. Cycle, etc.)
Fuel Required
Capacity (MW)
Date Utility Contacted
Date Proposal Submitted
Date Utility Responded
Pass/Fail Initial Screening?

Proposal's Significant Deficiencies (reason for failure)
Best or Most Viable Proposal During Filing Period (even if it fails the initial screening)

The evaluation process should also include the reporting of additional specific information for each NUG proposal that passed the initial screening, as follows:

Began Detail Evaluation?
Pass/Fail Economic Evaluation?
Pass/Fail Technical Evaluation?
Risks/Uncertainties
Proposal's Significant Deficiencies (reasons for failure)
Negotiations Continuing?

The evaluation process should include:

(1) An appropriate length of time within which a NUG could expect a utility response to its proposal (as a reasonable guide, not an absolute restriction);

(2) A sufficiently comprehensive list of information which the utility needs from a NUG in order to have the minimum details necessary for evaluation of a NUG proposal (both for the initial screening and also for the detailed evaluation);

(3) An appropriate list of methods, assumptions and supporting rationale generally used for evaluation of NUG proposals, including the kinds of modification the utility might make to a NUG proposal for purposes of evaluation; and

(4) A description of the utility's specific process for evaluating NUG proposals. (This may be a description of the Company's competitive bidding process, where applicable.)

The evaluation process should not require utilities to share information with NUGs regarding the utilities own costs and construction plans, because of the proprietary concerns of the utilities. NUG knowledge of a utility's costs of construction for a specific project may give the NUG an unfair advantage in a competitive market and can prevent the utility from obtaining the best price from a NUG.

IT IS, THEREFORE, ORDERED as follows:

1. That the findings and conclusions of this Order are hereby adopted as the Commission's current analysis and plan for the expansion of facilities to meet the future requirements for electricity in North Carolina pursuant to G.S. 62-110(c).

2. That the least cost integrated resource plans filed by CP&L, Duke, NC Power and Nantahala in this proceeding are approved as being in compliance with the requirements of Commission Rules R8-56 through R8-60.

3. That the Joint Stipulations entered into by CP&L, Duke and NC Power in this proceeding regarding each Company's LCIRP activities are hereby approved as proposed by the parties. Copies of the stipulations by CP&L, Duke and NC Power are attached to this Order as Appendices A, B and C, respectively.

4. That the DSM cost recovery and incentive mechanism stipulations entered into by CP&L, Duke and NC Power are hereby approved. The calculation of rewards under those stipulations shall be based upon a 19-year planning horizon excluding end effects. Copies of the Stipulations by CP&L, Duke and NC Power are attached to this Order as Appendices D, E and F, respectively.

5. That CP&L, Duke, NC Power and Nantahala shall file comments and/or suggested revisions regarding the Proposed Guidelines for Evaluation of Unsolicited NUG Proposals as described in the discussion of Finding of Fact No. 12 herein, and that such comments shall be filed within 90 days after the date of this Order. Intervenors shall also file comments and/or suggested revisions they may wish to make regarding the guidelines described herein within 90 days after the date of this Order. Reply comments by any party shall be filed within 120 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

For Appendices See Official Copy of Order in Chief Clerk's Office.

DOCKET NO. E-100, SUB 65

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Rulemaking Proceeding to Implement North Carolina Electric Membership Corporation Participation in Least Cost Integrated Resource Planning Proceedings) ORDER AMENDING RULES

BY THE COMMISSION: On May 17, 1990, the Commission issued an Order in Docket No. E-100, Sub 58, our first proceeding under current integrated resource planning (IRP) rules, in which the Commission concluded that North Carolina

Electric Membership Corporation (NCEMC) should be required to participate in future IRP proceedings. NCEMC appealed this decision, but the Court of Appeals found the issue "not ripe" for determination.

By Order of March 3, 1992, the Commission initiated the present rulemaking proceeding to consider the appropriate participation of NCEMC in future proceedings. The Commission provided for the filing of initial comments and proposed rules and the filing of reply comments. The Commission made the Public Staff and NCEMC parties and allowed other interested persons to petition to intervene. Subsequently, the Attorney General, Carolina Power & Light Company (CP&L), Duke Power Company (Duke), and Virginia Electric and Power Company intervened as parties.

Comments and proposed rules were filed by NCEMC and the Public Staff on June 3, 1992. Reply comments were filed by the Public Staff, NCEMC and CP&L on November 6, 1992. Duke filed reply comments on November 10, 1992. Additionally, the Commission has received letters from Broad River Electric Cooperative, Mountain Electric Cooperative, Blue Ridge Mountain Electric Membership Corporation, Tri-State Electric Membership Corporation, and Mecklenburg Electric Cooperative asking that they be exempted from any requirement that individual EMCs participate in IRP proceedings.

Upon concluding the latest IRP proceedings in Docket No. E-100, Sub 64, the Commission found good cause to proceed with this rulemaking docket. The Commission issued an Order on August 17, 1993, scheduling an oral argument. Oral argument was held as scheduled on September 7, 1993. NCEMC, the Public Staff, CP&L and Duke participated. The oral argument and the proposed rules filed by the Public Staff on June 3, 1993, and NCEMC on November 6, 1993, identify the points in contention.

The Public Staff believes that the Commission has jurisdiction over NCEMC and individual EMCs as to the full range of IRP. NCEMC, on the other hand, acknowledges jurisdiction as to the supply-side aspects of IRP proceedings, but denies that the Commission has authority over it as to demand-side planning and programs. Still, NCEMC volunteers to produce certain demand-side information and it argues that it is not necessary for the Commission to address the jurisdictional issue. Both Duke and CP&L argue that the Commission has statutory authority to require full participation by NCEMC and that NCEMC competes with them and should be subject to the same IRP requirements.

The proposed rules of the Public Staff and NCEMC reflect their positions on the jurisdictional issue. The Public Staff would amend the applicability section of the Commission's current IRP rules, Commission Rule R8-56(b), to apply the rules to NCEMC and individual EMCs. NCEMC, on the other hand, proposes to leave the current rules dealing with utilities untouched. NCEMC would add a new rule at the end to deal with its participation in IRP proceedings.

The Commission's current IRP rules and procedures are the result of an investigation and rulemaking proceeding initiated by Commission Order of March 25, 1987. Those proceedings were initiated upon finding "a need to establish express policies and rules to ensure that the present ad hoc case-by-case approach to planning becomes a fully integrated approach leading to the implementation of both supply-side and demand-side energy planning on a least-cost basis." (Emphasis added.) G.S. 62-110.1 was cited as authority for those proceedings. G.S. 62-2(3a), which NCEMC cites as the basis for demand-side policies, had not even been enacted when the Commission initiated its investigation. (G.S. 62-2(3a) was enacted June 12, 1987.) The Commission believes now, as we did in March 1987, that G.S. 62-110.1 provides sufficient authority for the Commission's IRP rules and proceedings. We reject NCEMC's argument that G.S. 62-110.1 deals only with supply-side policies and that G.S. 62-2(3a) provides the sole basis for demand-side policies. This argument ignores the fact that supply-side and demand-side activities are really inextricable. Since the Commission's IRP rules and procedures are based on G.S. 62-110.1, and since G.S. 62-110.1 applies to EMCs operating within the State, the Commission concludes that it has authority to subject NCEMC to the requirements of the IRP rules.

The Commission believes now, as we did when we issued our May 17, 1990 Order in Docket No. E-100, Sub 58, that it is necessary and appropriate to include NCEMC in our IRP proceedings. The Commission does not believe that the current rules should be extended to individual EMCs. NCEMC is a generation and transmission cooperative that supplies the wholesale power requirements of its 27 members, which are distribution cooperatives providing retail electric service. EMCs serve over half a million customers in North Carolina and cover about 60% of the State's territory. NCEMC owns a partial interest in the Catawba Nuclear Station and owns generation facilities of approximately 650 megawatts. NCEMC's member cooperatives operate about 1 megawatt of generation of their own. Their contracts with NCEMC prohibit them from constructing further generation facilities and require them to remain members of NCEMC well into the next century. There are six distribution cooperatives operating in the State that are not members of NCEMC. Five are incorporated in contiguous states and provide service in limited areas across the border. The sixth is French Broad EMC. French Broad has agreed to provide information to NCEMC for inclusion in its IRP filings. The above facts were stated in writing and during oral argument herein and we accept them as true. We believe that they provide a basis for including NCEMC in the current rules since its activities have a significant impact on electric generation and planning for the State as a whole. We find no basis for including the individual distribution cooperatives who are members of NCEMC since their separate generating capacity is insignificant. We find no basis for including the non-member distribution cooperatives since those that are incorporated out-of-state serve very small geographic areas and since French Broad EMC has agreed to provide information to NCEMC.

In the interest of simplicity and consistency, the Commission concludes that the best way to implement these decisions is to amend the applicability section of the current rules to include NCEMC. The Commission will therefore amend Commission Rule R8-56(b) by adding a second sentence to read as follows: "As of October 29, 1993, these rules are applicable to the North Carolina Electric Membership Corporation." By amending the applicability section, the Commission is applying all rules in Article 11 of Chapter 8 of the Commission Rules to NCEMC.

The Public Staff further proposed that Commission Rule R8-58 be amended by adding a second introductory paragraph as follows:

> North Carolina statutes do not provide the Commission with jurisdiction over NCEMC and individual EMCs for ratemaking purposes. However, the Commission is authorized to review the least cost plan of

> NCEMC and/or individual EMCs. Therefore, NCEMC and/or individual EMCs shall provide a least cost integrated resource plan in accordance with Commission rules. NCEMC shall be specifically excused from providing projections of individual EMC retail rates, projections of individual EMC retail revenue requirements, or supporting information used to develop those projections. NCEMC may utilize the format requirement for plans submitted to the Rural Electrification Authority (REA) to the extent possible in meeting Commission requirements.

The Commission finds this amendment unnecessary. It is true that the Commission has no ratemaking jurisdiction over NCEMC, but the Commission is not asserting such jurisdiction and there is no need to include that sentence in our Rules. The sentence excusing NCEMC from providing projections of <u>retail</u> rates and <u>retail</u> revenue requirements led to considerable misunderstanding. NCEMC interpreted it as requiring projections of <u>wholesale</u> rates and revenue requirements, but that was not the Public Staff's intent. The Public Staff now asks that the sentence be deleted. Since the current rules do not require such projections, we see no need for the sentence. Both the Public Staff and NCEMC propose that NCEMC be allowed to use the format of plans that it submits to the Rural Electrification Authority to the extent possible. We agree, but we see no need to state this in our Rule since it deals only with <u>format.</u> By agreeing, the Commission is not excusing NCEMC from any of the <u>content</u> required by our Rules. NCEMC proposed a sentence to the effect that it shall not be required to provide trade secrets or commercially sensitive information. The Commission has always tried to protect such information, and we will continue to do so. We need no sentence to this effect.

IT IS, THEREFORE, ORDERED that Commission Rule R8-56(b) should be, and hereby is, amended by adding a second sentence to read as follows: "As of October 29, 1993, these rules are applicable to the North Carolina Electric Membership Corporation."

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION

(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-100, SUB 66

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates For Sale and Purchase of Electricity Between Electric Utilities and Qualifying Facilities- 1992	))))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on April 20-21, 1993

BEFORE: Commissioner Allyson K. Duncan, Presiding; Chairman William W. Redman, Jr., and Commissioners Sarah Lindsay Tate, Robert O. Wells, Julius A. Wright, Charles H. Hughes, and Laurence A. Cobb

APPEARANCES:

For Carolina Power & Light Company:

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For North Carolina Power:

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Edward S. Finley, Jr., Attorney at Law, Hunton & Williams, Post Office Box 109, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

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For Carolina Industrial Group for Fair Utility Rates I and II:

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For the Using and Consuming Public:

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Margaret A. Force, Associate Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27606

BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission pursuant to G.S. 62-156(b) to establish rates for small power producers as that term is defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become "qualifying facilities," and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying facility status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, which are in the public interest, and which do not discriminate against cogenerators or small power producers. The FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers shall reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to the electric utilities, the implementation of these rules was delegated to the state regulatory authorities. Implementation may be accomplished by the issuance of regulations on a case-by-case basis or by any other means reasonably designed to give effect to the FERC's rules.

The Commission at the outset determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest of many such proceedings held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by five electric utilities to the qualifying facilities (QFs) which are interconnected with them. The Commission has also reviewed and approved other related matters involving the relationship between the five electric utilities and the qualifying facilities interconnected with them, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also involves the carrying out of this Commission's duties under the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. G.S. 62-156 provides that "no later than March 1, 1981, and at least every two years thereafter" this Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those which are prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" is more restrictive in G.S. 62-156 than the PURPA definition of that term, in that it includes only hydroelectric facilities of 80 megawatts or less, thus excluding users of other types of renewable resources.

On July 14, 1992, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing in this proceeding. That Order made Carolina Power & Light Company (CP&L), Duke Power Company (Duke), Virginia Electric and Power Company, d/b/a North Carolina Power (NC Power), Nantahala Power and Light Company (Nantahala), and Western Carolina University (WCU) parties to the proceeding to establish the avoided cost rates each is to pay for power purchased from qualifying facilities pursuant to the provisions of Section 210 of PURPA and the FERC regulations implementing those provisions and to establish the rates each is to pay for power purchased from small power producers as required by G.S. 62-156. The Order required each of the five utilities to file certain specified data and any direct testimony by the date established in the Order.

On July 22, 1992, the Attorney General filed his notice of intervention.

By Order dated September 16, 1992, the Commission rescheduled the hearing to begin April 20, 1993, required the utilities to file the required information by November 13, 1992, and all other parties to intervene and file direct testimony by March 16, 1993. Duke, CP&L, WCU and NC Power filed testimony on November 13, 1992. Nantahala filed its testimony on February 26, 1993.

On December 11, 1992, the Carolina Industrial Group for Fair Utility Rates (CIGFUR I and II), an industrial group comprised of Federal Paper Board Company, Inc., Huron Chemicals of America, Inc., LCP Chemicals & Plastics, Inc., Monsanto Company, Texasgulf, Inc., and Weyerhauser Company, filed a petition to intervene. The Commission allowed CIGFUR I and II to intervene.

On December 30, 1992, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene. By Order dated January 5, 1993, the Commission allowed CUCA to intervene.

On February 22, 1993, petitions to intervene were filed by Tim Henderson and Charles Henderson. Howard F. Twiggs filed a petition to intervene on February 23, 1993. Michael R. Allen petitioned to intervene on March 1, 1993. Lyn Bullock and Steve Cook petitioned to intervene on March 2, 1993. State Hydro and William H. Lee petitioned to intervene on March 8, 1993, and March 11, 1993, respectively. The DFI Group, Inc. also filed a petition to intervene on March 11, 1993.

The Commission allowed the petitions to intervene on behalf of Tim Henderson, Luther Allen, Charles Henderson, Howard F. Twiggs and Michael R. Allen by Order dated March 11, 1993. The Commission granted the petitions of William H. Lee and DFI Group, Inc. by Order dated March 15, 1993. The petition of Steve Cook was allowed by Order dated March 23, 1993. The petition of Lynn Bullock was granted by Order dated March 31, 1993.

NC Power filed its Motion for Interim Relief on March 5, 1993, requesting approval on an interim basis, of its proposed rates and standard contract. The Public Staff filed a response on March 18, 1993, objecting to the approval of the standard contract and requesting that Plymouth Power Partnership be excluded from any interim rate approval. Plymouth Power Partnership and Enviro Gen, Inc., filed petitions to intervene on April 7, 1993. Enviro Gen also filed comments. North Carolina Cogeneration Partners filed a petition to intervene and comments on April 13, 1993. Plymouth Power filed comments on April 15, 1993. On April 16, 1993, the Commission entered its Order on Motion for Interim Relief wherein it granted interim approval of NC Power's proposed rates pending hearing and final determination, as to all QFs except Plymouth Power Partnership.

On April 15, 1993, NC Power filed the rebuttal testimony of Jeffrey L. Jones, Daniel J. Green, and James P. Carney. On April 15, 1993, the Public Staff filed the supplemental testimony of Ben Johnson.

The Commission issued Orders on April 16, 1993, granting the petitions to intervene of Winston Moore and J. Herb Warren, which were filed on April 12, 1993.

On April 19, 1993, Duke Power filed its rebuttal testimony of Steven K. Young and Kenneth B. Keels, Jr.

On April 28, 1993, the Public Staff filed its Motion for Reconsideration of the Commission's Order On Motion for Interim Relief, requesting that Enviro Gen be allowed to sign a contract at the rates in effect in 1992 when it contacted NC Power. By motion filed April 29, 1993, Enviro Gen joined in this motion. NC Power filed its response in opposition to the motions for reconsideration on May 6, 1993. North Carolina Cogeneration Partners filed its motion for reconsideration on May 7, 1993. By Order dated May 18, 1993, the Commission denied the motions for reconsideration.

On March 29, 1993, WCU filed a motion requesting that its testimony be copied into the record without the presence of its witness and that it be excused from appearing at the hearing. By Order dated April 16, 1993, the Commission granted WCU's motion.

In addition to the foregoing, there were other motions, Orders, and filings not specifically mentioned, which are matters of record.

The matter came on for hearing on April 20, 1993, as previously noticed and scheduled. The prefiled testimony of George W. Wooten, offered on behalf of WCU, was copied into the record without Mr. Wooten being present to testify. Pursuant to the stipulation of all the parties, the prefiled testimony of Nantahala witness N. Edward Tucker, Jr., was copied into the record without Mr. Tucker being present to testify.

NC Power presented the testimony of a panel consisting of its employees as follows: Jeffrey L. Jones, Director - Capacity Contracts; Daniel J. Green, Director - Planning Services; James P. Carney, Assistant Treasurer and Assistant Corporate Secretary; and Kurt W. Swanson, Regulatory Specialist. Witness Jones discussed the status of the Company's non-utility power production contracts and explained the proposed changes to the Company's standard contract. Witness Green discussed NC Power's generation expansion plan which is the basis for the Company's avoided cost rates and avoided energy mixes. He also discussed the line loss component of the proposed rates. Witness Carney's testimony addressed the issue of the appropriate split between capacity and energy payments to the qualifying facilities. Witness Swanson presented a revised Rate Schedule 19 - Power Purchases from Cogeneration and Small Power Production Qualifying Facilities.

Duke Power Company presented the testimony of a panel consisting of its employees as follows: Kenneth B. Keels, Jr., Purchased Power Contacts Manager in the Planning and Operating Department; and Steven K. Young - Manager of the Rate Department. Witness Keels testified regarding the Company's experience with QFs, and he presented the Company's proposed changes to the standard Purchased Power Agreement which is used to develop the standard contract. Witness Young presented testimony and calculations supporting the Company's proposal for a revision of Schedule PP, Purchased Power.

Carolina Power & Light Company offered the testimony of G. Wayne King, Principal Engineer, Rates and Energy Services Department for CP&L. Witness King presented updates to the Commission on the amount of QF capacity on CP&L's system and presented a proposed Cogeneration and Small Power Producer Schedule CSP-15A, which is based on projections of avoided cost. He testified that the proposed Schedule CSP-15A is an update of existing Schedule CSP-14 and is based partly on the methodology previously approved by the Commission and partly on agreements reached between CP&L and the Public Staff.

The Public Staff presented the testimony of Ben Johnson, Ph.D., Consulting Economist and President of Ben Johnson Associates, Inc. Witness Johnson recommended several modifications to the rate schedules proposed by Duke, CP&L and NC Power.

At the beginning of the hearing, parties of record Michael Allen, J. Herb Warren, Tim H. Henderson, Lyn Bullock, Luther Allen, William H. Lee and Steve Cook asked to appear as public witnesses notwithstanding their prior interventions. Based upon the agreement of all parties, the Commission allowed each of these individuals to appear and present testimony as public witnesses in return for the waiver by each witness of his right of cross examination as a party of record.

Leroy Townsend also appeared as a public witness. All of the public witnesses testified generally in support of small hydro projects and questioned the adequacy of established avoided cost rates.

Rebuttal testimony was presented by witnesses Keels and Young for Duke Power Company and by witnesses Jones, Green and Carney for NC Power.

All parties to the preceding were provided the opportunity to file proposed orders with the Commission within 30 days after the April 29, 1993, mailing of the final transcript in the proceeding.

Based on the foregoing, the testimony and exhibits offered at the hearing and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. CP&L and Duke should offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities

of 80 megawatts or less capacity owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility contracting to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more years should include a condition making contracts under those options renewable for subsequent term(s) on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rate and other relevant factors or (2) set by arbitration.

2. NC Power shall continue to offer long-term levelized capacity payments with energy payments based on a long-term levelized generation mix with adjustable fuel prices for 5- 10- and 15-year periods as standard options to QFs which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility contracting to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more years should include a condition making contracts under those options renewable for subsequent term(s) on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rate and other relevant factors or (2) set by arbitration.

3. NC Power should offer long-term levelized energy payments as an additional option to small QFs rated at 100 kW or less capacity.

4. Nonhydroelectric qualifying facilities contracting to sell generating capacity of more than five megawatts to either Duke or CP&L should have the options of contracts at the variable rates set by the Commission herein or contracts at negotiated rates and terms.

5. Nonhydroelectric qualifying facilities desiring to sell generating capacity of more than five megawatts to NC Power should participate in NC Power's competitive bidding process for obtaining additional capacity.

6. Nantahala and WCU should not be required to offer any long-term levelized rate options to qualifying facilities.

7. It is not appropriate at this time for the Commission to set specific guidelines for negotiations between utilities and qualifying facilities. All utilities should negotiate in good faith with qualifying facilities.

8. Appropriate protection for the utilities against financial loss due to default by a QF on a contract for long-term levelized rates is a matter best left to negotiation between the utilities and those nonhydroelectric QFs contracting to sell more than 5 mW capacity. Hydroelectric QFs contracting to sell 80 mW or less capacity and nonhydroelectric QFs contracting to sell 5 mW or less capacity should not be required to offer such protection against financial loss.

9. The input assumptions used by NC Power, Duke and CP&L to calculate avoided costs are generally consistent with each utility's historical operating experience, published forecasts and escalation rates, and data used by other utilities for similar purposes.

10. Duke and CP&L use the peaker method to develop avoided capacity costs. NC Power uses the DRR methodology. Both the peaker method and the DRR method are generally accepted and used throughout the electric utility industry and are reasonable for use in this proceeding.

11. CP&L, Duke and NC Power should be required to re-examine in detail in the next biennial avoided cost proceeding the justifications for the peaker and DRR methodologies.

12. The nuclear capacity factors recommended by the Public Staff for calculating avoided cost rates for CP&L are appropriate for this proceeding.

13. CP&L's 1.0124 working capital allowance factor should be applied to its fixed O&M costs as well as its variable O&M costs in calculating avoided cost rates for CP&L in this proceeding.

14. CP&L's use of the EPRI Technical Assessment Guide data for determining the fixed O&M costs of new combustion turbines is appropriate for purposes of this proceeding.

15. CP&L should be allowed to revise its standard contract in order to incorporate the $30 and $75 reconnection charges established in its last general rate case as discussed herein.

16. Duke should be allowed to calculate its avoided capacity costs using a combination of 74 mW and 132 mW combustion turbines for purposes of this proceeding.

17. Duke should be allowed to calculate its avoided capacity costs using a fixed O&M component based on its 1992 Future Generation Data Base Manual for purposes of this proceeding.

18. Duke should be required to apply its 1.0334 working capital allowance factor to its fixed O&M costs as well as its variable O&M costs for purposes of this proceeding.

19. Duke should be allowed to calculate its avoided capacity costs excluding a component for general plant. However, the matter of general plant costs should be addressed in more detail in the next biennial avoided cost proceeding.

20. Duke should be required to calculate its avoided capacity costs using a 20% performance factor for purposes of this proceeding.

21. Duke should be allowed to modify its standard contract in order to require QFs to begin paying interconnection facilities charges on the date the interconnection facilities become operational, subject to the force majeure provisions as discussed herein.

22. Duke should be allowed to modify its standard contract in order to authorize withholding of Duke payments owed to a QF in an amount necessary to offset QF payments owed to Duke.

23. NC Power's proposed avoided capacity rates reflect an allowance for avoided general plant.

24. For purposes of this proceeding only, NC Power's avoided capacity rates should be increased by 0.1 percent to reflect an allowance for working capital.

25. For purposes of this proceeding only, NC Power's proposed avoided energy rates should be increased by 1.3 percent to reflect an allowance for working capital.

26. NC Power should study the issue of working capital as it relates to the DRR methodology in order to determine an appropriate adjustment, and present its findings and solutions in the next biennial avoided cost proceeding.

27. The split between capacity costs and energy costs produced under NC Power's DRR methodology is appropriate and should be approved.

28. NC Power's capacity payment calculations should be based on its proposed 2730 on-peak hours in lieu of a performance adjustment as proposed by the Company.

29. NC Power should not be allowed to modify its standard contract in the manner proposed in this proceeding in order to include a provision authorizing reduction in power purchases from a QF during off-peak hours.

30. NC Power should not be allowed to modify its standard contract in order to require a security deposit.

31. NC Power should not be allowed to modify its standard contract in order to specify a minimum level of liability insurance.

32. NC Power should be allowed to modify its standard contract in order to require quarterly reports.

33. NC Power should be allowed to modify its standard contract in order to authorize withholding of NC Power payments owed to a QF in an amount necessary to offset QF payments owed to NC Power.

34. NC Power should not be allowed to modify its standard contract in order to require QFs to begin paying interconnection facilities charges on the date the interconnection facilities become operational as proposed in this proceeding.

35. Proposed Rate Schedule CG for Nantahala Power and Light Company is reasonable and appropriate.

36. Western Carolina University's proposed Small Power Production Supplier Reimbursement Formula is reasonable and appropriate.

37. The rate schedules, contracts and terms and conditions proposed by CP&L, Duke and NC Power in this proceeding should be approved subject to the modifications discussed herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 3

The evidence in support of these findings of fact is contained in the testimony of CP&L witness King, Duke witnesses Young and Keels, NC Power witnesses Jones and Green, and Public Staff witness Johnson.

A major issue in prior avoided cost proceedings has been whether the Commission should require the electric utilities to offer long-term levelized rates to qualifying facilities as standard rate options. Long-term levelized rates are permitted, but not required, by the regulations implementing Section 210 of PURPA. The commentary to the regulations includes the following:

> A facility which enters into a long-term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a state regulatory authority or nonregulated electric utility from approving such an arrangement.

G.S. 62-156(b)(1), which applies to small power producers as defined by G.S. 62-3(27a), provides that "long-term contracts for the purchase of electricity by the utility from small power producers shall be encouraged in order to enhance the economic feasibility of small power production facilities."

Prior to this proceeding, CP&L, Duke and NC Power were required to offer standard long-term levelized rate options to small qualifying facilities. The standard long-term levelized rate options were ordered by this Commission in order to encourage the development of cogeneration and small power production facilities. As a result of concerns raised by the utilities and the Public Staff in previous proceedings with respect to the effect of these options, the Commission limited the standard long-term levelized rate options to hydroelectric facilities of 80 mW or less and to nonhydroelectric qualifying facilities with generating capacity of five megawatts or less. In this proceeding the utilities proposed no change in the availability of long-term levelized rates.

The General Assembly has clearly indicated in G.S. 62-156 a policy of encouraging hydroelectric facilities. Additionally, we note that many of the risks associated with standard long-term levelized rate options are either not present or tend to be minimized in the case of most hydroelectric facilities. For example, hydroelectric facilities are not subject to the risks associated with changes in fossil fuel costs or the business risks associated with the heat recovery aspect of cogeneration projects. Further, more of the capital costs involved in a hydroelectric facility tend to be "up front" costs which must be financed. Levelized rates facilitate financing by providing a degree of certainty and by allowing an income stream which more evenly matches the debt payments required by financing. Finally, hydroelectric facilities by their very nature tend to entail a degree of permanence and stability as regards the major components of the facility, such as the dam and powerhouse. In light of the foregoing reasons, we believe and conclude that CP&L and Duke should continue to offer long-term levelized rate options to hydroelectric qualifying facilities less than 80 mW as standard rate options.

With respect to nonhydroelectric qualifying facilities contracting to sell five megawatts or less, CP&L and Duke should continue to offer long-term levelized rate options. As noted in previous Orders, the risks associated with a nonhydroelectric qualifying facility in the event of a default on a long-term levelized rate contract of five megawatts or less capacity is relatively small in terms of dollar exposure and impact on supply when contrasted with the risks associated with such a default on a larger contract. In addition, standard rate options will tend to encourage small projects, the owners of which probably would not have the resources or the expertise to negotiate with the utility.

Thus, based on the foregoing and the record as a whole in this proceeding, the Commission concludes that CP&L and Duke should offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity owned or operated by a small power producer as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility contracting to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration.

The evidence and conclusions supporting the finding of fact for NC Power is the same as that set forth herein for Duke and CP&L. However, instead of a fixed long-term levelized energy payment, NC Power offers an energy payment based on a long-term levelized generation mix with adjustable fuel prices. NC Power has proposed no change to the limitation on the availability of its Schedule 19 and no party has opposed the limitation. Accordingly, NC Power should continue to offer long term levelized capacity payments with energy payments based on a long-term levelized generation mix with adjustable fuel prices for 5-year, 10-year and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility which contracts to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rate and other relevant factors or (2) set by arbitration.

In the previous avoided cost proceeding, the Commission found that NC Power should offer a fixed long-term levelized energy payment as an option to small QFs rated at 100 kW or less capacity. Accordingly, the Commission concludes herein that NC Power should continue to offer the long-term levelized energy payment option to small QFs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 AND 5

As in previous avoided cost proceedings, the Commission continues to believe that nonhydroelectric QFs contracting to sell greater than 5 mWs of generating capacity to either CP&L or Duke should have the options of contracts at the variable rates set by the Commission herein or contracts at rates derived by free and open negotiation with the utility.

As in past proceedings, NC Power's competitive bidding solicitation program has been explained to the Commission and the Commission concludes that nonhydroelectric facilities desiring to sell generating capacity of more than five megawatts to NC Power should participate in NC Power's competitive bidding process for obtaining additional capacity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The conclusion that Nantahala should not be required to offer any standard long-term levelized rate options to qualifying facilities flows from the Commission's conclusions in the previous biennial proceedings that the unique nature and circumstances of Nantahala's power supply arrangements make such options infeasible. That conclusion has not been challenged by any party in this proceeding. While Nantahala owns some generating units, it is unable to service its load from those sources alone. It therefore must purchase capacity and/or energy under contract from others. Because of these contractual arrangements and the inherent uncertainty and monthly variations involved in such arrangements, it is not feasible to require Nantahala to offer any form of standard long-term levelized rate options to qualifying facilities.

The same considerations apply to WCU. WCU has no generating facilities of its own and buys all of its power from Nantahala under an arrangement which is similar to that between Nantahala and TVA in the past.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 AND 8

The Commission expects all utilities to negotiate in good faith with qualifying facilities for such terms as are fair to the qualifying facility as well as to the utility's ratepayers. The Commission takes this opportunity to stress again the responsibility of the utilities in these negotiations. Any qualifying facility may file a complaint with the Commission if it feels that a utility is not negotiating in good faith.

As in the past, the Commission will set no specific guidelines for such negotiations. We would expect such negotiations to address such problems as the following:

(a) The appropriate contract duration and the parties' best forecast of avoided capacity and energy credits over the duration;

(b) Capacity credits that reflect the need (or lack of need) for additional capacity at the time deliveries under the contract are actually to be made;

(c) The availability of capacity during the utility's daily and seasonal peak periods;

(d) The utility's ability to dispatch the qualifying facility;

(e) The expected or demonstrated reliability of the qualifying facilities;

(f) The terms and provisions of any applicable contract or other legally enforceable obligation, including the termination notice requirement and sanctions for noncompliance:

(g) The extent to which the scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility;

(h) The usefulness of capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(i) The individual and aggregate value of the capacity from qualifying facilities on the utility's system;

(j) The smaller capacity increments and the shorter lead times which might be available with additions of capacity from qualifying facilities;

(k) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from the qualifying facility;

(l) The alternative of long-term rates that are not levelized or only partially levelized;

(m) The alternative of long-term rates that include levelized capacity payments and variable energy payments;

(n) Appropriate notice prior to the expiration of the contract term, the renewability of the contract, and provisions of setting the appropriate rates for such renewed contract; and

(o) The appropriate security bond or other protection for the utility if levelized or partially levelized payments are negotiated.

Negotiated contracts between a utility and a qualifying facility should, upon execution, be submitted to the Commission and such contracts will be accepted for filing. Such contracts, after being filed, shall be subject to review in the context of the utility's general rate cases or by a complaint proceeding, just as would any other contract by the utility.

As in past proceedings, the Commission concludes in this proceeding that appropriate protection for the utilities against any financial loss they might suffer if a qualifying facility with a long-term contract at levelized rates defaults after receiving overpayments during the early part of the contract is a matter best left to negotiation between the utilities and those nonhydroelectric qualifying facilities contracting to sell more than five megawatts capacity. The Commission will generally not require such protection for hydroelectric qualifying facilities or for nonhydroelectric qualifying facilities contracting to sell less than five megawatts capacity.

Duke and NC Power proposed modifications to their standard contracts that would provide various protections against financial loss, and the Public Staff generally opposed the Duke and NC Power proposals. The specific proposals are addressed separately herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 AND 10

The evidence in support of these findings of fact is contained in the testimony of NC Power witness Green, Duke witness Young, CP&L witness King, and Public Staff witness Johnson.

The Commission found in prior avoided cost proceedings that the input assumptions used by CP&L, Duke and NC Power to calculate avoided costs are generally consistent with each utility's historical operating experience, published forecasts and escalation rates, and data used by other utilities for similar purposes. Except for instances described elsewhere herein, neither the methodologies nor the assumptions used in those methodologies were contested by the parties to this proceeding.

The Differential Revenue Requirement (DRR) methodology requires a utility to identify how it would adjust its schedule of planned capacity additions in response to an increase in power supplied by QFs. The change in costs associated with the adjustment is used to calculate avoided capacity costs. The DRR methodology is used by NC Power to develop avoided capacity costs and energy costs.

The peaker methodology requires a utility to develop marginal capacity costs using the supply-side resource with the lowest investment cost for achieving peak capacity, which is usually a combustion turbine. The peaker methodology is used by both Duke and CP&L to develop avoided capacity costs.

The peaker method and the DRR method should produce similar results in situations where a utility has identified a near-term need for new peaking capacity. The Commission has found that both the peaker method and the DRR method are generally accepted and used throughout the electric utility industry and the Commission has approved the use of both methods in past proceedings. Accordingly, the Commission concludes that the DRR methodology as applied by NC Power and the peaker methodology as applied by Duke and CP&L are reasonable for purposes of this proceeding.

CUCA contended in its legal brief that if avoided capacity costs are based on a peaking unit, then avoided energy costs should also be based on a peaking unit. The Commission has pointed out in previous Orders in these biennial proceedings that the fixed costs of a peaking unit represent a proxy for the capacity related portion of the fixed costs for any avoided generating unit. However, the energy costs of a peaking unit are not an appropriate proxy for the average avoided energy costs of the entire generation mix. Capacity costs are avoided only at the time of the system peaks, while energy costs are avoided at all times round the clock. Energy costs are dependent on the generation mix. A change in the generation mix results from a different dispatch of all generating units together as a whole and not from redispatching a single generating unit alone.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. II

The evidence for this finding of fact is found in the testimony of Public Staff witness Johnson and the hydroelectric developers who testified at length concerning their efforts and the problems they see with the peaker methodology as implemented by Duke and CP&L.

Witness Johnson testified that the peaker methodology produced rates at the low end of reasonableness. The hydroelectric developers indicated concern about the divergence in the utilities' retail rates and their avoided cost rates.

The Public Staff noted that while Duke and CP&L's immediate capacity needs are for peakers, base load plants are projected within the overall planning period. The Public Staff recommended that a generic investigation should be undertaken to determine if the peaker method should be retained or if another method, such as the Differential Revenue Requirement (DRR) methodology, should be approved for use in developing avoided cost rates in North Carolina.

CUCA contended in its legal brief that the Commission should determine avoided cost rates for North Carolina's three major electric utilities by examining their expansion plans, determining which units are avoidable, and predicating the avoided cost computations upon the capacity and energy costs associated with those avoidable units. Furthermore, CUCA contended that if the Commission continues to allow adherence to the DRR and peaker methodologies, it should avoid application of those methodologies in such a manner as to further understate the capacity and energy costs which the electric utilities would avoid by purchasing power from a cogenerator or small power producer.

CUCA contended that PURPA and accompanying regulations require that the establishment of rates for the purchase of electric power by electric utilities from QFs be based on the fully avoided cost of alternate sources of electric energy and to be sufficient to encourage the development of cogeneration and small power production. It contended that the avoided cost rates established in prior biennial proceedings in North Carolina have proven completely inadequate to encourage cogeneration and small power production, and it cited a lack of significant QF activity in North Carolina as proof that PURPA requirements are being violated.

In view of the concerns raised by the Public Staff, hydroelectric developers and CUCA, the Commission is of the opinion that the justifications for the DRR and peaker methodologies should be re-examined in detail in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 AND 13

The evidence for these findings of fact is found in the testimony and exhibits of CP&L witness King and Public Staff witness Johnson.

The evidence shows that CP&L made very few changes to the avoided capacity costs it calculated in Docket No. E-100, Sub 59. CP&L made no change in its general plant adjustment factor nor in its marginal loss factor. CP&L adjusted its capacity credits by applying a performance adjustment of 20%.

CP&L derived its estimate of the installed cost per kW for its avoided capacity costs from the costs of three neighboring electric utilities. From the average cost of $374, the CAPCOST program generated total plant investment in 1992 dollars of $410. This was escalated at 5% to derive the $430.50 in 1993 dollars used in the avoided capacity cost calculations. The resulting cost of $430.50 per kW is close to the figure accepted by the Commission in the last biennial proceeding.

Witness King testified that the rates in CP&L's proposed Cogeneration and Small Power Producer Schedule CSP-15A were based on the same methodology the Commission approved in establishing the rates in Schedule CSP-14 in Docket E-100, Sub 59. Witness King sponsored exhibits which established that CP&L's projected avoided capacity cost of $430.50/kW in 1993 dollars was based on the cost of a 75 mW combustion turbine. Witness King further testified that CP&L's proposed avoided energy rates were based on ENPRO computer model analyses.

Subsequent to the filing of CP&L witness King's testimony and exhibits, CP&L and the Public Staff reached an agreement with respect to the just and reasonable avoided cost rates for CP&L with the exception of the appropriate fixed O&M cost to be used to calculate CP&L's capacity credits. Public Staff witness Johnson testified in his supplemental testimony that based upon CP&L's agreement to use certain lower nuclear capacity factors for the purposes of this proceeding that CP&L's revised proposed energy rates were reasonable. Similarly, with the exception of the above-referenced disagreement regarding CP&L's fixed O&M costs, witness Johnson testified that CP&L's agreement to apply its 1.0124 working capital allowance factor to fixed O&M costs as well as to variable O&M costs for purposes of this proceeding would mean that CP&L's proposed capacity credits in CSP-15A were reasonable.

CUCA offered no evidence, but attempted to establish through cross-examination that declining avoided cost rates were the cause of decreased QF activity as well as a hinderance to the economic feasibility of existing and future developments. During cross-examination by CUCA, CP&L witness King testified that declining rates had some effect on the decrease in QF activity, but that there were additional reasons. Witness King cited exhaustion of the resource itself, procedural issues that could be raised in contracting for that kind of power, and various perceptions over what the market was going to look like in the future as opposed to what it looks like now.

Notwithstanding the contention made by CUCA, the issue before this Commission is the establishment of each utility's avoided cost, not the rate level necessary to make QF projects economically feasible for developers. Therefore, based on the testimony of CP&L witness King and Public Staff witness Johnson, the Commission concludes that CSP-15A is just, reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding of fact is found in the testimony and exhibits of CP&L witness King and Public Staff witness Johnson.

The fixed O&M costs of CTs were calculated by CP&L to be $1.08 per kW, rather than the $.66 per kW used by CP&L in its previous avoided cost analysis. The fixed O&M costs used in CP&L's estimates were taken from the September 1989

EPRI Technical Assessment Guide (TAG). CP&L increased the EPRI estimates by 15% to adjust for the ambient temperature of the plant's operation. These adjusted 1988 costs were then escalated to 1992 dollars using DRI cost indices and escalated to 1993 dollars by using the inflation rate of 5.0% (also derived in part from DRI projections) that the Company assumed elsewhere in its avoided cost calculations.

Witness Johnson testified that CP&L's estimate of $1.08 per kW appears quite low, although it is more reasonable than the $.66 figure the Commission approved in the last proceeding.

Witness Johnson testified that in the current proceeding CP&L did not use EPRI TAG data for its estimated fixed capital cost of CTs, and that consistency would suggest the use of a different approach to fixed O&M costs as well. He testified further that historical data for the Company's O&M costs for its operating CTs suggest that $1.08 is an unrealistically low figure. Accordingly, he followed the same method he used to estimate fixed O&M costs for Duke Power, and applied that methodology to CP&L's historical cost data. His resulting fixed O&M figure of $3.04 per kW is significantly higher than the $1.08 estimated by the Company.

On cross-examination, witness Johnson conceded that the O&M costs of a new combustion turbine are probably different from those of CP&L's existing combustion turbines which, on average, are 23 years old. The Commission is aware of the considerable uncertainty associated with estimating such future costs. Until such costs are known with relative certainty, a reasonable approach is to use an industry planning guide such as the TAG. The Commission concurs with the approach taken by CP&L for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in the testimony and exhibits of CP&L witness King and Public Staff witness Johnson.

CP&L has proposed to increase its reconnect charges from $7.50 to $27.50 for reconnections occurring during business hours and to $91.59 for those occurring during all other hours. Witness Johnson recommended that the Commission increase the charge to $30 for business hours and $75 for all other hours. The basis for witness Johnson's recommendation was that the Commission recently established these same charges for reconnection of service for CP&L's retail customers in Docket No. E-2, Sub 637. CP&L contends that its costs to provide these services are $27.82 and $91.59, respectively.

The Commission agrees with the Public Staff regarding this matter and concludes that the reconnection charges should be set at the same $30 and $75 levels established in the most recent general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16 - 20

The evidence for these findings of fact is found in the testimony of Duke witness Young and Public Staff witness Johnson. There are four issues in controversy with respect to Duke's proposed avoided capacity rates. These are: (1) the appropriate capital cost of the combustion turbine (CT); (2) the appropriate amount of fixed operations and maintenance (O&M) costs, including working capital; (3) the appropriate amount of avoided general plant to be included; and (4) the appropriate performance adjustment factor.

Duke calculated its avoided capacity costs using the projected installed costs of two differently sized combustion turbines. In the Company's 1992 Integrated Resource Plan, the PROVIEW program selected 74 mW CTs as the least-cost expansion alternative in years prior to 1999 and 128 mW CTs from 1999 onward. In this proceeding, the Company has used 132 mW CTs and has stated that the 132 mW turbine is similar to the type of turbine that Duke may add after 1998.

The avoided capacity costs for the years 1993 through 1998 were derived from the estimated installed cost of an 80 mW CT, with summer capacity rating of 74 mW, using data from a current Duke contract with General Electric. The Company's calculations reflect the average cost per unit of a 10-unit facility, with an assumed on-line date for the last of the units of September 1, 1996. The annual projected construction costs plus AFUDC for the years 1992 through August 1996 were summed and divided by the summer capacity rating of 74 mW. This was then expressed in 1993 beginning-year dollars by de-escalating the cost at an annual rate of 5.5%, to arrive at a cost of $409.23 per kW.

The avoided capacity costs for the years 1999 through 2007 were derived from the estimated installed cost of a 159 mW CT with a summer capacity rating of 132 mW, using oil as the fuel. This cost represents the average cost per unit of a six-unit facility with construction costs and AFUDC spread over a four-year construction period. The sum of these annual costs was divided by the summer capacity rating and then de-escalated to 1993 beginning-year dollars, using the same inflation rate of 5.5%, to yield a per-kW cost of $429.14.

The installed capacity costs were then expressed as annual carrying costs by applying fixed charge rates of 8.74% and 8.51% to the costs of the 74 mW and 132 mW CTs, respectively. The Company calculated its fixed charge rates using an inflation rate of 5.5%, a discount rate of 9.10% and an assumed 25-year life for each of the plants. The 9.10% discount rate was calculated using a capital structure of 49% common equity, 41% long-term debt, and 7.80% preferred stock, taken from the Company's Long-Term Financial Plan. Duke used a return on equity of 12.50%, the return authorized by the Commission.

Duke next added fixed O&M expenses to the annualized CT costs. These O&M expenses, in 1993 dollars, were $1.18 per kW for the years 1993-98 and $.95 per kW for the years 1999-2007. These costs were derived from the Company's 1992 Future Generation Data Base Manual used in the development of its Least Cost Plan.

The sum of the annual CT carrying costs and annual O&M expenses were then adjusted by a performance factor of 1.164. In the previous avoided cost determination proceeding, Duke had used a factor of 1.20. Lastly, the costs were adjusted by two marginal loss adjustment factors, to develop separate rates for distribution level and transmission level QFs. The distribution level factor was derived from the on-peak marginal system loss of 4.427%. The transmission level factor, reflecting only the losses incurred in the use of a step-up transformer, was .318%.

The capacity credits Duke has estimated for transmission level QFs are $43.14 per kW per year in the years 1993-98 and $43.75 per kW per year in the years 1999-2007. For QFs interconnecting at the distribution level, the analogous annual capacity payments are $45.00 per kW and $45.64 per kW, respectively.

These annual capacity costs, which are in 1993 dollars, were converted to nominal dollars using an annual inflation rate of 5.50%. To calculate the variable capacity costs, the 1993 and 1994 nominal dollar capacity credits were present valued to 1993 at a 9.10% discount rate and expressed as levelized monthly payments. In the case of the long-term fixed contracts, the same methodology was followed, summing the annual capacity credits for the years covered by the contract and levelizing the present value of these costs.

The annual avoided capacity costs were split between off-peak and on-peak periods by applying the seasonal allocation ratios of 77% on-peak, 23% off-peak, approved by the Commission in Docket No. E-100, Sub 41. These ratios were divided by the seasonal peak hours to determine the seasonal capacity credits expressed as cents per kWh. With 2,773 peak hours during on-peak months and 1,387 peak hours during off-peak months, the "peak" category for this calculation includes numerous shoulder period hours, as well as the true peak hours.

AVOIDED TURBINE COSTS

For the avoided capacity cost of the 74 mW CT ($409.23 per kW), Duke's estimate was taken from a contract that Duke has with General Electric; the $429.14 per kW installed cost of the 159 mW CT, with summer capacity rating of 132 mW, is an estimate for a generic unit. These estimates are lower than those used by Duke in the previous avoided cost proceeding, which equate to $422 and $483 when escalated to 1993 dollars. However, in its September 1992 Section 292.302 filing with this Commission, Duke estimated the cost of the Lincoln CTs at $454 per kW, in 1995 dollars, which equates to $407 per kW in 1993 dollars, when de-escalated at the 5.5% rate the Company has used in its avoided cost computations.

Public Staff witness Johnson testified that Duke's avoided capacity cost calculations could have been simplified by reliance on one estimate rather than two. He stated that it would be preferable to use the estimate for which there is supporting documentation. However, the two estimates are fairly close and both approximate the data CP&L used for CT costs. Witness Johnson recommended that the installed cost per kW of $409.23, for which the Company states it has a contract, be used and that the second CT cost estimate used in the Company's study be omitted.

The Commission concludes that Duke should be allowed to calculate its avoided capacity costs using a combination of 74 mW and 132 mW combustion turbines for purposes of this proceeding. The long-term levelized rates established herein will span the time frame represented by the two CT sizes. The information supporting the Duke estimates is used systemwide by Duke for planning purposes.

FIXED O&M COSTS

With respect to the appropriate level of fixed O&M costs, witness Johnson testified that he found the significant decreases in Duke's avoided capacity costs over those of two years ago are largely caused by the Company's exclusion of overhaul costs from its fixed O&M figures. In Docket No. E-100, Sub 59, the Company added approximately $11 per kW in fixed O&M "overhaul" costs (in 1991 dollars) to the CT capital costs. This was in addition to $2.68 per kW of other fixed O&M costs. Witness Johnson noted that in deriving its avoided capacity costs in the instant docket, however, Duke adopted the methodology employed by CP&L in the previous docket, and did not include overhaul costs as a separate component of fixed O&M costs.

Witness Young testified in rebuttal that overhaul costs are not shown as a separate item in the PROMOD runs for the projected CTs but are included in the variable O&M costs.

Nevertheless, witness Johnson pointed out that the current estimate of $1.18 per kW is less than half of the $2.68 figure approved by the Commission in the last proceeding and that Duke Power's projected fixed O&M costs are now only slightly higher than the $1.08 per kW estimated by CP&L in its avoided capacity cost calculations.

Witness Johnson modified Duke's calculations by employing a fixed O&M cost of $3.69 per kW, which was calculated from the O&M expenses contained in the Company's Form 1 for the years 1989 through 1991 for its combustion turbines. To disaggregate these total O&M expenses between fixed and variable expenses, he used Duke's 1993 estimate of its variable O&M costs for CT's as a proxy for its actual variable O&M costs per kWh; and he treated the balance of the O&M costs as fixed costs.

Witness Young stated that it is inappropriate for witness Johnson to use embedded fixed costs for 1960-70 vintage combustion turbines as an estimate for the O&M fixed costs of combustion turbines to be constructed in the mid-1990s. He said that the CTs on which witness Johnson based his analysis are different models and are much smaller than the type Duke is using to determine its avoided costs. He said witness Johnson is matching the capital cost of new CTs with an estimate of the fixed O&M cost for Duke's old CTs.

The source of Duke's fixed O&M expenses is the Company's 1992 Future Generation (Cost) Data Base Manual used in the development of its Integrated Resource Plan. Witness Young acknowledges that Duke's fixed O&M cost estimates have decreased from the previous filing, noting that better information is available based on surveys Duke has made of other utilities that own and operate the type of peaking capacity that will be added to the Duke system in the future. He further stated that Duke has had extensive discussions with vendors regarding this type of CT, and the Company has two more years' experience in internal analysis of this information.

The Commission finds that Duke has not omitted the overhaul cost from the avoided costs estimates, but has included them in the variable O&M figures. The Commission agrees that an O&M expense estimate for CTs of 1960s and 1970s vintages is inappropriate to utilize for CTs to be constructed in the mid-1990s, and approves Duke's use of engineering studies based on the specific turbines to be built on the Duke system to properly match the O&M cost of new turbines with the capital cost of new turbines. The Commission concludes that Duke's level of fixed O&M in its capacity credit calculation should be approved as filed.

Witness Johnson applied a working capital allowance adjustment of 1.0334 to the fixed O&M costs, noting that Duke had applied the adjustment to variable O&M and had neglected to apply it to fixed O&M. Witness Young testified that Duke had adopted the methodology presented by a Public Staff witness in Docket No. E-100, Sub 41A to derive a working capital adjustment to be applied to variable O&M. At that time, the Commission ordered Duke to make the adjustment, and Duke has continued to utilize this adjustment.

For purposes of this proceeding, the Commission concludes that Duke should be required to apply its 1.0334 working capital allowance factor to its fixed O&M costs as well as its variable O&M costs, consistent with similar determinations for CP&L and NC Power herein.

GENERAL PLANT COSTS

Witness Johnson testified that unlike CP&L, Duke did not adjust its capacity costs to include general plant costs. This discrepancy occurs despite the fact that both utilities used the peaker method. Duke has stated that it excluded general plant costs because the general plant costs were approximately offset by extraordinary ratemaking, engineering, and other costs associated with QFs.

Witness Johnson testified that while the ratemaking, billing, and other costs related to QFs cited by Duke do exist, they are not directly analogous to the general plant costs in question. Rather, they are more akin to general and administrative expenses as opposed to investment.

Witness Johnson concluded that since the general and administrative expense increases associated with QFs are offset by general and administrative expense decreases, the general plant costs remain to be accounted for. Consequently, a general plant adjustment should properly be included in Duke's avoided cost calculations, just as one is included in CP&L's analysis. Witness Johnson recommended the use of a factor of 1%, which equals the factor used by CP&L.

Witness Young testified that some of Duke's generating capacity is from purchases, including QF purchases. Since Duke meets its load requirements with its own generating plants and purchased power, including QF purchased power, it is just as appropriate to allocate general plant costs to purchased power (including QF capacity) as it is to allocate such costs to Duke-owned capacity. An allocation of embedded general plant costs to both type of capacity would show that any potential decrease in general plant costs resulting from avoided Duke-owned capacity is offset by an equivalent amount of general plant costs allocated to Duke's purchased QF capacity. Thus, when both the potential increase in general plant costs [due to the incorporation of QF facilities on the Duke system] and the potential savings in general plant costs [due to avoiding Duke-owned capacity] are considered, they offset each other and no general plant costs are avoided.

Witness Young testified that in order to incorporate QF generating resources into the Duke system, Duke has had to appropriate human resources and associated general plant costs for avoided cost rate design, rate case preparations and filings, engineering studies for design and costing of interconnection facilities, preparation and handling of purchased power contracts, customer accounting and billing. He said that Duke employs people who perform such jobs and they use office space, computer facilities, furniture and other general plant facilities.

The Commission concludes that for purposes of this proceeding Duke should be allowed to calculate its avoided capacity costs excluding a component for general plant. There is considerable uncertainty as to what extent a utility's general plant costs associated with its own generation are offset by the utility's general plant costs associated with its power purchases from QFs. Because of this uncertainty, the Commission finds good cause to adopt Duke's position regarding this issue. However, the matter of general plant costs should be addressed in more detail in the next biennial avoided cost proceeding.

PERFORMANCE ADJUSTMENT FACTOR

Duke recalculated the performance adjustment factor in this proceeding and is no longer adjusting capacity costs by 20%. Its "performance adjustment factor" is now 16.4%. Witness Johnson testified that the reduction would have the effect of discouraging QF development in North Carolina, since it reduces the variable and fixed term rates calculated by the Company by approximately 3%.

Witness Young testified that the performance factor is incorporated into the capacity credit in order to recognize that a QF will not generate at full capacity 100% of the time due to forced outages and planned maintenance outages. He stated that the performance factor was designed to allow for 560 planned maintenance hours and 41 forced outage hours during the peak hours of the off-peak months, as well as 139 forced outage hours during the peak hours in the peak months, resulting in a total outage allowance of 740 peak hours annually. Witness Young noted that the outage hours are based on data associated with CT capacity similar to the CT capacity data used to develop the capacity credits. The performance factor enables the QF to receive 100% of the avoided capacity cost while still experiencing some scheduled and forced outages.

Witness Young explained that the performance factor of 1.20 included in the current Schedule PP, approved in Docket No. E-100, Sub 59, was based on a 20% reserve margin which incorporated factors including forced outages, maintenance outages, load forecast error, weather variations and other unexpected operating conditions. He stated that the performance factor should incorporate only the impacts of forced outages and planned maintenance outages associated with the peaking resource used to develop the capacity credits.

The Commission concludes that Duke should be required to calculate its avoided capacity costs using a 1.20 performance factor for purposes of this proceeding. Such a factor is consistent with the factor approved in previous avoided cost proceedings and is the factor used by CP&L herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21 AND 22

The evidence for these findings of fact is found in the testimony and exhibits of Duke witness Keels and Public Staff witness Johnson.

Duke proposed a modification of its standard contract to address the issue of when it is appropriate to begin charging QFs for interconnection facilities. Witness Keels testified that Duke believes that QF payments should begin when the interconnection facilities are installed at the request of the supplier and made available for that supplier's use. Duke proffered a provision to that effect in the previous biennial avoided cost proceedings. At that time, the Public Staff raised concerns that a situation might arise in which the interconnection facilities would be installed and, for some reason beyond its control, the QF would be unable to produce electricity but would still have the obligation to pay the monthly charges. The Commission concluded in the prior proceeding that Duke's proposed provision should not be approved, and that Duke could petition the Commission for recovery of the interconnection facilities charges when circumstances warranted such relief. In the current proceeding, Duke again proposed a provision which would obligate the QF to begin paying the interconnection facilities charges on the date the interconnection facilities become operational. However, as reflected in late-filed Duke Exhibit KBK-3, Duke has modified its proposal to change Paragraphs 3.4 and 5.3 so that if the QF is prevented from beginning the delivery of electricity to Duke by reason of force majeure as defined in Paragraph 7 of the Purchased Power Agreement, and thus the initial delivery date is postponed, then the QF is not obligated to pay the interconnection facilities charges during the pendency of the condition of force majeure prior to the initial delivery date.

The Public Staff stipulated its agreement with the modified version of the Duke proposal. The Commission concludes that Duke should be allowed to modify its standard contract in order to require QFs to begin paying interconnection facilities charges on the date the interconnection facilities become operational, subject to the force majeure provisions as discussed herein.

Duke also proposed a modification to its standard contract in which Duke reserves the right to set off against any sums it owes to a QF, any sums due from the QF to Duke, such as unpaid interconnection facilities charges or "... past due balances on any accounts Supplier has with Company for other services." Duke witness Keels cited the recent example of the owner of three hydroelectric facilities which delivered electricity to Duke. The same owner's industrial company failed to pay Duke for electric service and built up a substantial unpaid balance owed to Duke prior to filing for bankruptcy. In said case, the customer actually proposed a set off, but there were no contractual provisions approved to implement that concept. Had Duke been able to utilize an offset as proposed, Duke might have been able to reduce the magnitude of its $150,000 loss on the service account.

Public Staff witness Johnson testified that he opposed the setoff provision proposed by Duke. He stated that the QF sells and receives power under separate tariffs and separate contracts, and that it is more appropriate to keep these transactions separate.

The Commission concludes that Duke's proposed contract modification regarding setoffs would potentially allow Duke to reduce writeoffs from customers who do not pay their bills, thus reducing the need for Duke's paying customers to absorb the cost of the unpaid electric service. Therefore, the Commission approves Duke's proposed Paragraph 8 as set forth in Duke Exhibit KBK-2.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23 - 26

The evidence for these findings of fact is found in the testimony and exhibits of NC Power witnesses Green, Carney and Swanson and Public Staff witness Johnson.

The evidence indicates that NC Power used the Differential Revenue Requirement (DRR) method, as it has in previous proceedings, to determine both its avoided capacity costs and its avoided energy mix. With this method, both capacity and energy costs are developed via computer models that simulate the operation of the system.

To calculate capital costs and operating costs of the system and determine its lowest cost generation expansion plan, the Company formerly used the EGEAS model. Now it uses the PROVIEW model. Given current generation and load forecast data, and a group of candidates as future generation resources, PROVIEW selects the most economical generation alternatives. The plan with the lowest calculated net present value is adopted as the lowest cost generating alternative.

The data for the generation expansion plan selected by PROVIEW is then input to PROMOD to develop the system energy costs. To calculate avoided capacity and energy costs, the Company ran both the PROVIEW and PROMOD models twice. First, the optimal generation expansion plan inputs were used in PROVIEW to determine the capacity costs of the optimal expansion plan, and the plant operating data were input to PROMOD to calculate the operating costs associated with this system configuration.

Then the models were run a second time, assuming an additional 200 mW of QF capacity at zero cost. The added QF capacity causes the delay or elimination of some plant additions called for in the Company's base case expansion plan. Avoided capacity costs are thus calculated as the difference in the revenue requirements of the two PROVIEW runs.

Avoided energy costs are calculated as the difference in total operating costs calculated by the two PROMOD runs. The difference in total operating costs, divided by the QF generation, equals the estimated avoided energy costs per kW. The differences in generation and heat rate between the two plans are used to derive the avoided energy mixes.

Witness Johnson testified that based on his review the assumptions used in the PROVIEW models were reasonable. He testified that NC Power is planning an extensive construction program, replacing all but three of its current baseload plants, and all of its combustion turbines, by the year 2022. Over the 30 years of the plan, NC Power is planning to build more than 15,000 mW of new baseload capacity and over 6,000 mW of peaking capacity. The net change--megawattage added from new plants less the megawattage of the plants that appear to be retired--is 13,497 mW of added capacity in Plan W (the scenario with the added QF capacity) and 13,803 mW of added capacity in Plan W/O (the original scenario without the QF capacity).

The Company's planned generation additions include 21 CTs and 37 pulverized coal plants. The generation alternatives considered by the Company were four-unit CT installations of 88 mW per unit, with summer capacity ratings of 76.5 mW per unit. NC Power also considered combined-cycle plants of two 210 mW units, with summer capacity ratings of 185 mW, and 400 mW pulverized coal plants, with a summer capacity rating also of 400 mW.

Only the pulverized coal and CTs were selected by the Company's model in developing its lowest-cost plan. This plan, used as the base case in the calculation of avoided capacity costs, included the addition of one four-unit, gas-fired CT plant with total summer capacity of 306 mW in 1997, seven additional 306 mW CT plants between 1998 and 2001, and a 400 mW pulverized coal plant to be installed by 2002.

The capital costs used by NC Power, all expressed in 1992 dollars, were $338 per kW for the combustion turbine, $837 per kW for the advanced combined cycle, and $1,542 per kW for the pulverized coal. The fixed O&M costs of the CT, however, are estimated by NC Power at $5.40 per kW (1992 dollars), while CP&L and Duke have estimated $1.08 and $1.18 per kW, respectively.

In his testimony and exhibits, Public Staff witness Johnson adjusted NC Power's avoided capacity cost by 1.10 percent and its avoided energy charges by 1.3 percent to account for working capital. Witness Johnson attributed roughly 1.0 percent of the 1.10 percent adjustment to general plant costs, which he stated NC Power failed to account for in its capacity rates, and the remaining 0.1 percent to working capital.

It is the opinion of the Commission that NC Power witness Green has satisfactorily shown in his rebuttal testimony that the Company's cost estimates for avoided capacity do contain an allowance for general plant. Therefore, it would not be appropriate to include the additional allowance for general plant. For purposes of this proceeding, the 1.10 percent factor should be reduced to 0.1 percent to account for working capital only. The Company agreed that the 1.3 percent adjustment to its avoided energy charges was appropriate for this proceeding.

The Commission is further of the opinion that NC Power should study the issue of working capital as it relates to the DRR methodology in order to determine an appropriate adjustment, and present its findings and solutions in the next biennial avoided costs proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27 - 29

The evidence in support of these findings of fact is found in the testimony and exhibits of NC Power witnesses Jones, Green and Carney.

In the previous biennial avoided cost proceeding, the Commission directed NC Power to examine three issues and report its findings on the three issues in the current avoided cost proceeding.

First, NC Power was directed to examine its DRR methodology to determine if a better split could be made between its energy costs and capacity costs. NC Power presented testimony in the current proceeding supporting its DRR methodology from a "conceptual" point of view. Public Staff witness Johnson agreed with the NC Power presentation. No other party filed testimony refuting NC Power's conclusions.

Second, NC Power was directed to re-examine its calculation of capacity payments on the basis of 3120 hours in order to determine if it was consistent with its application of a 20% performance adjustment. NC Power presented testimony in the current proceeding supporting its calculation of capacity payments on the basis of 2730 hours, and supporting capacity factors in its models of 71 percent on-peak and 34 percent off-peak in lieu of a performance adjustment. No party challenged the new calculation methodology.

Third, NC Power was directed to examine its experience in Virginia regarding reduction of energy purchases from QFs during off-peak periods. NC Power reported in the current proceeding that the five QFs in Virginia subject to the reduction during off-peak hours did not yield any useful information. Four of the five operate only on-peak, and the fifth has just become operational.

Nevertheless, NC Power proposed in the current proceeding to modify its standard contract for QFs in order to enable the Company to reduce its purchases from QFs for up to 1,000 hours per load during off-peak hours. The Commission rejected a similar proposal by NC Power in the last biennial avoided cost proceeding, and directed the Company to monitor its Virginia QFs in order to determine the effect of its proposal in Virginia and to report is findings in the next avoided cost proceeding.

In the current proceeding, NC Power witness Jones indicated that the Company is willing to include the following guidelines in its standard contract in order to govern the conditions under which it would reduce purchases from QFs:

1. When fossil steam generating units are operating at minimum output.

2. When hydro units are discharging minimum water needed to maintain reservoir levels.

3. When purchased power under other contracts are at minimum levels.

Public Staff witness Johnson testified that neither CP&L nor Duke have such a provision allowing the utility to reduce purchases from QFs during light load conditions. The reduction in off-peak energy purchases from QFs could have serious financial impacts on certain QFs, particularly hydro facilities (where fixed costs are built into the off-peak energy charge as well as the on-peak energy charge). Furthermore, some cogenerators may be required by their industrial process to continue operating during the utility's off-peak hours.

In the prior avoided cost proceeding, Public Staff suggested that any dispatch provision included in Schedule 19 should also contain language to protect the QFs, by specifying the precise criteria for curtailing purchases. It was recommended that NC Power be allowed to reduce QF power purchases only when the following conditions were all met:

> During conditions where customer demand for power is at a low level, all on-line fossil steam generating units are operating at their <u>minimum generation levels</u>; all NCP purchase and interchange transactions are operating at <u>minimum take levels</u>, and further reductions in customer loads would either require NCP to "dump"

> power or incur increased costs due to unit shut down and start-up costs. At these times, and not to exceed 1,000 hours a year, NCP can reduce power purchases from its QF contracts at its discretion.

The dispatch provision that NC Power is proposing in its Revised Schedule 19 contains none of these safeguards for the QFs. It states as follows:

> The Company shall have the right to reduce the power received from a QF during periods where light load conditions exist on the Company's system. Downward dispatch will be limited to 1000 off-peak hours in any calendar year.

The Commission is of the opinion that the proposal to reduce purchases from QFs during light load conditions, as written, should be denied. However, the Commission notes that the Company has proposed to include some language in its standard contract which might satisfy the concerns of the Public Staff, but that there is insufficient discussion in the record or in the proposed orders in this proceeding to determine if the proposed language is sufficient. The Commission concludes that the proposal to reduce purchases from QFs during light load conditions should be denied without predjudice to the Company seeking reconsideration of a modified proposal which contains language sufficient to address the concerns raised herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30 - 34

The evidence for these findings of fact is found in the testimony of NC Power witness Jones and Public Staff witness Johnson.

NC Power proposed replacing its current standard contract with a new contract identical to that used by the Company in Virginia. Witness Jones stated that the current North Carolina contract and the earlier contract in use in Virginia "were very simple contracts which were intended to facilitate the development of projects by developers with limited resources." The new contract, according to the Company, incorporates additional requirements relating to posting of security, regulatory disallowances, project status reporting to facilitate interconnection activities, insurance and evidence of maintaining QF certification.

First, NC Power is proposing to modify its standard contract for QFs in order to enable the Company to reduce its purchases from QFs during light load conditions. The Commission has concluded elsewhere herein that the proposal should be denied without prejudice to the Company's seeking reconsideration of a modified proposal.

Second, NC Power is asking for a security deposit of $36 per kW of the contracted capacity, which it will retain until the contract is terminated. This is not a provision of the current North Carolina contract. Neither Duke nor CP&L has such a provision in their contracts. The Commission has explicitly rejected proposals of this kind in prior avoided cost proceedings. In Docket No. E-100, Sub 53, Duke proposed a "performance bond" for all QFs contracting with the Company under levelized rate schedules. NC Power also proposed that similar protection be furnished by all QFs under long-term rate schedules in that proceeding. The Commission rejected those provisions in that docket. Most recently, the Commission rejected such provisions in Docket No. E-100, Sub 59, stating as follows:

> As in past proceedings, the Commission concludes in this proceeding that appropriate protection for the utilities against any financial loss they might suffer if a qualifying facility with a long-term contract at levelized rates defaults after receiving overpayments during the early part of the contract is a matter best left to negotiation between the utilities and those nonhydroelectric qualifying facilities contracting to sell more than five megawatts capacity. The Commission will not require such protection for hydroelectric qualifying facilities or for nonhydroelectric qualifying facilities contracting to sell less than five megawatts capacity.

The Commission concludes that NC Power should not be allowed to modify its standard contract for QFs in order to require a security deposit.

Third, NC Power wants written proof of general liability insurance of $1,000 per kW of nameplate rating, and it wants the total amount of liability insurance to be not less than $1,000,000. In addition, the QF would be required to adjust such coverage from time to time to reflect revised general liability insurance requirements as determined and requested by NC Power.

In the current North Carolina contract there is a provision that the QF operator will provide written proof of "appropriate liability insurance", but no dollar amount of what is considered appropriate is stated. Neither Duke nor CP&L has such a provision in its contract. The Public Staff contends that the utility can readily obtain adequate insurance of its own, and most likely can obtain such coverage at lower rates than the QF.

The Commission agrees with the Public Staff that NC Power should not be allowed to modify its standard contract for QFs in order to specify a minimum level of liability insurance.

Fourth, NC Power wants the QF to furnish the Company with a monthly status report on the project, beginning three months after execution of the contract and continuing until the commercial operation date of the QF. The current contract does not contain such a provision. Neither Duke nor CP&L has such a provision in its contract. The Public Staff contends that the new language would impose a burden on the QF which does not appear to be necessary or appropriate. It contends that requiring a formal written report so often imposes a burden on the QF that would probably be far out of proportion to any benefit that the utility would gain.

The Commission concludes that NC Power should be allowed to modify its standard contract for QFs in order to require quarterly status reports from the QFs rather than the monthly status reports proposed herein.

Fifth, NC Power proposes to modify its standard contract in order to withhold NC Power payments owed to a QF in the amount necessary to offset QF payments owed to NC Power. NC Power contended that the provision is necessary to protect ratepayers from nonpayment of bills owed to the utility.

Public Staff witness Johnson testified that the NC Power proposal is similar to the Duke proposal in this proceeding. The Public Staff objected to both proposals on grounds that transactions in which the utility owes payments to a QF are separate from transactions in which the QF owes payments to the utility, and that the two types of transactions should be kept separate.

The Commission concludes that NC Power's proposal to modify its standard contract in order to withhold NC Power payments owed to a QF in the amount necessary to offset QF payments owed to NC Power should be approved consistent with the Commission's decision to approve the similar Duke proposal herein.

Sixth, NC Power proposes to modify its standard contract in order to require QFs to begin paying interconnection facilities charges on the date the interconnection facilities become operational. NC Power contended that once the interconnection facility is in place, the costs to the ratepayers have begun, so payments from the QF should also begin.

Public Staff witness Johnson testified that the proposal could place an undue burden on a QF if the Company completes the interconnection facility earlier than needed by the QF. The Public Staff's objection to the NC Power proposal is the same in principle as its original objection to the similar Duke proposal, but it differs to the extent that Duke's proposal contains a force majeure clause applicable to both the utility and the QF while the NC Power proposal does not contain a force majeure clause at all.

The Commission agrees with the Public Staff that NC Power should not be allowed to require QFs to begin paying interconnection facilities charges on the date the interconnection facilities become operational as proposed in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

The evidence pertaining to Nantahala's calculations of avoided cost rates is contained in the testimony of Nantahala witness Tucker, which was stipulated into the record. According to his prefiled testimony, the rates in Nantahala's proposed Schedule CG differ from the standard rates currently approved by the Commission. The rates previously approved were based on the new power supply arrangement with Duke. The Schedule CG proposed in this proceeding is designed to reflect the actual avoided cost resulting from Nantahala's new power supply arrangement with Duke Power. Because Duke must supply all of Nantahala's incremental load, Duke's avoided cost is the appropriate basis of Nantahala's standard rate.

The Commission notes that no other party to this proceeding presented an evaluation or took issue with Nantahala's proposed rate schedule or purchase power agreement, and concludes that they should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence pertaining to WCU's calculation of avoided costs is contained in the testimony and exhibits of WCU witness Wooten, which were stipulated into the record. WCU does not generate its own electricity but buys its power at wholesale from Nantahala Power and Light Company at rates approved by the FERC. The avoided cost formula proposed by WCU would reimburse a qualifying facility based on the rates charged to WCU by Nantahala at any point in time, and is the same formula approved by the Commission in the previous avoided cost proceeding. No party challenged the avoided cost formula proposed by WCU. The Commission concludes that the proposed Small Power Production Supplier Reimbursement Formula should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence and conclusions for this finding of fact are cumulative and are reflected in the foregoing findings and conclusions. The rate schedules, contracts, and terms and conditions of service proposed by the three major utilities in this proceeding are generally reasonable except as discussed elsewhere herein, and they should be approved subject to the modifications discussed herein.

IT IS, THEREFORE, ORDERED as follows:

1. That CP&L and Duke shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility contracting to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more years should include a condition making contracts under those options renewable for subsequent term(s) on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rate and other relevant factors or (2) set by arbitration.

2. That NC Power shall offer long-term levelized capacity payments with energy payments based on a long-term levelized generation mix with adjustable fuel prices for 5-year, 10-year and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility which contracts to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration.

3. That NC Power shall offer long-term levelized energy payments as an additional option for small QFs rated at 100 kW or less capacity.

4. That Duke and CP&L shall offer nonhydroelectric qualifying facilities contracting to sell generating capacities of more than five megawatts the options of contracts at the variable rates set by the Commission or contracts at negotiated rates and terms.

5. That nonhydroelectric qualifying facilities desiring to sell generating capacity of more than five megawatts to NC Power shall participate in NC Power's competitive bidding process for obtaining additional capacity.

6. That Nantahala and WCU shall not be required to offer any long-term levelized rate options to qualifying facilities.

7. That the rate schedules, contracts and terms and conditions proposed in this proceeding by CP&L, Duke, NC Power, Nantahala and WCU are hereby approved, subject to the modifications discussed herein.

8. That Duke, CP&L, NC Power, Nantahala and WCU shall file within 10 days after the date of this Order rate schedules, contracts, and terms and conditions of service implementing the findings of fact, conclusions and ordering paragraphs herein.

9. That CP&L, Duke and NC Power shall file testimony and exhibits as appropriate in the next biennial avoided cost proceeding addressing a detailed re-examination of the peaker and DRR methodologies.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of July 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-100, SUB 67

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Consideration of Ratemaking Standards)
Pursuant to Section 712 of the Energy) ORDER
Policy Act of 1992)

HEARD IN: Commission Hearing Room, Dobbs Building, Raleigh, North Carolina, July 7, 1993

BEFORE: Commissioner Allyson K. Duncan, Presiding; Chairman John E. Thomas, and Commissioners William W. Redman, Jr., Charles H. Hughes and Laurence A. Cobb

APPEARANCES:

For Carolina Power & Light Company:

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For Cogentrix, Incorporated:

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For LG&E Power Systems, Inc. and Westmoreland-LG&E Partners:

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For Himself:

Wayne S. Leary, 1006 Albemarle Court, New Bern, North Carolina 28562

BY THE COMMISSION: This proceeding was instituted for the purpose of complying with the provisions of Section 712 of the Energy Policy Act of 1992 (EPACT). Section 712 amends Section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA), by adding a tenth paragraph to Section 111(d), which is codified as 16 U.S.C. 2621(d). Subsection (a) of Section 111 provides that each State regulatory authority shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of Title I of PURPA.

By Order dated March 16, 1993, the Commission initiated a generic consideration of the new standards established by Section 712 of EPACT, scheduled a public hearing for July 7, 1993, provided for public notice, and established deadlines for interventions and the prefiling of expert testimony. Carolina Power & Light Company (CP&L), Duke Power Company (Duke Power), Virginia Electric & Power Company, d/b/a North Carolina Power (NC Power), and Nantahala Power & Light Company (Nantahala) were made parties to this proceeding.

The following parties intervened: the Attorney General, Carolina Industrial Group for Fair Utility Rates (CIGFUR-II), Carolina Utility Customers Association, Inc. (CUCA), Cogentrix, Inc., North Carolina Electric Membership Corporation (NCEMC), the Public Staff, Wayne S. Leary, Westmoreland-LG&E Partners and LG&E Power Systems.

CUCA's petition to intervene, filed April 23, 1993, requested the Commission to authorize CP&L, Duke Power, and NC Power to place more reliance upon purchased power resources and to consider the appropriateness of authorizing wheeling of electric power to end-users in North Carolina. By response filed May 3, 1993, Duke Power asked the Commission to deny CUCA's apparent attempt to expand the scope of the hearing. On May 20, 1993, the Commission issued its Order on Scope of Hearing, to the effect that the hearing was limited to the standards set forth in the March 16, 1993 Order.

The filing deadline for initial testimony was extended to May 26, 1993, by order dated May 3, 1993. On May 26, 1993, testimony was filed by CP&L, Duke Power, NC Power, Nantahala, Cogentrix, the Public Staff, and Westmoreland-LG&E Partners. Duke Power filed its reply testimony on June 17, 1993. NCEMC filed testimony on June 18, 1993.

On June 25, 1993, CUCA filed a motion to strike portions of the testimony of CP&L witness Sherwood H. Smith, Jr., on the ground that his testimony covered issues beyond the scope of the hearing. By response filed July 1, 1993, CP&L notified the Commission of an agreement it had reached with CUCA striking certain portions of witness Smith's testimony.

The matter came on for hearing as scheduled on July 7, 1993. Prior to the hearing, the parties had stipulated that the pre-filed testimony of the parties would be copied into the record and cross-examination would be waived. The following testimony was stipulated into the record:

CP&L: Sherwood H. Smith, Jr., Chief Executive Officer and Chairman of the Board of Directors; William A. Abrams, Senior Vide President of Duff & Phelps Credit Rating Agency; Verne B. Ingersoll, II, Manager of System Planning; and Larry L. Yarger, Manager - Fossil Fuel Department.

Ouke Power: William S. Lee, Chairman of the Board and President; Donald H. Oenton, Jr., Senior Vice President, Planning and Operating; and Richard J. Osborne, Vice President, Finance and Chief Financial Officer.

NC Power: James P. Carney, Assistant Treasurer and Assistant Corporate Secretary; and Gary L. Edwards, Manager - Capacity Acquisition.

Nantahala: N. Edward Tucker, Jr., Executive Vice President.

Cogentrix: Donald A. Dowling, Retired President and Chief Operating Officer of Cogentrix, Inc.

NCEMC: Gary D. Tipps, Vice President, Power Supply Division.

Public Staff: Robert E. Ciliano, Senior Vice President - RCG/Hagler, Bailly, Inc., and Director of the Integrated Resource Division; and Steven A. Mitnick, Principal - Utility Services Group - RCG/Hagler, Bailly, Inc.

Westmoreland-
LG&E Partners: Roy J. Shanker, Consultant.

Wayne S. Leary: For himself.

At the hearing, the Commission requested that proposed orders and briefs be filed and that the proposed orders and briefs specifically address whether implementation of the four standards would, or would not, carry out the purposes of PURPA. The parties agreed that information supplied in response to this question would be treated as evidence. The Commission further allowed reply briefs to be filed.

INTRODUCTORY FINDINGS

1. This proceeding was initiated by the Commission in compliance with the requirements of Section 712 of the Energy Policy Act of 1992 (EPACT), which amends Section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

2. Section 111 of PURPA requires this Commission to consider each of the standards therein and to make a determination concerning whether or not it is appropriate to implement such standards to carry out the purposes of Title I of PURPA. The purposes of Title I of PURPA are to encourage (1) conservation of energy supplied by electric utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers. The Commission may implement any such standard determined to be appropriate or may decline to do so.

3. Section 712 of EPACT amends Section 111 of PURPA to add the following paragraph:

(10) Consideration of the effects of wholesale power purchases on utility cost of capital; effects of leveraged capital structures on the reliability of wholesale power sellers; and assurance of adequate fuel supplies

(A) To the extent that a State regulatory authority requires or allows electric utilities for which it has ratemaking authority to consider the purchase of long-term wholesale power supplies as a means of meeting electric demand, such authority shall perform a general evaluation of:

(i) the potential for increases or decreases in the costs of capital for such utilities, and any resulting increases or decreases in the retail rates paid by electric consumers, that may result from purchases of long-term wholesale power supplies in lieu of the construction of new generation facilities by such utilities;

(ii) whether the use by exempt wholesale generators (as defined in section 79z-5a of Title 15) of capital structures which employ proportionally greater amounts of debt than the capital structures such utilities threatens reliability or provides an unfair advantage for exempt wholesale generators over such utilities;

(iii) whether to implement procedures for the advance approval or disapproval of the purchase of a particularlong-term wholesale power supply; and

(iv) whether to require as a condition for the approval of the purchase of power that there be reasonable assurances of fuel supply adequacy.

FINDINGS WITH RESPECT TO COST OF CAPITAL IMPACTS
SECTION 111(d)(10)(A)(i)

4. There is no current need for the Commission to issue additional rules or to adopt a standard regarding Section 111(d)(10)(A)(i) of PURPA.

5. A utility's risk and cost of capital may increase any time it expands generating capacity, whether the expansion is through long-term purchases or its own construction projects.

6. The risk associated with long-term purchases of power cannot be examined in isolation and must be compared with the risk associated with a utility construction project that would provide comparable resources.

7. The potential for increases or decreases in a utility's cost of capital as a result of its decisions whether to buy or build will vary for each utility depending upon (a) the risks associated with the utility constructing its own

plant and the way those risks are managed and (b) the risks associated with purchased power contracts, which depend upon the contractual arrangements between the lender and the Independent Power Producer (IPP) and between the purchasing utility and the IPP.

8. Utility cost of capital may be affected only when dependence upon long-term wholesale power purchases rises above a utility-specific threshold, which must be determined on a case-by-case basis.

9. The utility-specific determination of the appropriate level of dependency on purchased power may consider a number of factors, including the terms of existing purchased power contracts (whether take and pay versus take or pay); fuel diversification; the number and size of IPP projects in proportion to utility generating capacity assets; and the quality of IPP project ownership and mechanisms for mitigating problems.

10. The type and specific terms of a given purchased power contract are factors that must be considered in assessing the risk associated with long-term wholesale purchases of power (both for IPP projects and for purchases from other utilities).

11. The risk of IPP dependence can be managed through terms of the wholesale power contract that explicitly deal with contingencies such as a large increase in fuel prices, levels of required unit availability, dispatchability, and other operational interfaces with the utility.

12. The risk of IPP dependence also can be managed, as risk is generally managed in financial portfolios, through diversification -- achieving a mix of IPP versus utility owned and operated plants, and a variety of fuel types and suppliers, generating technologies, and IPP ownerships.

13. There is no clear, systematic pattern of bond deratings linked to dependency on purchased power.

14. The appropriate level of utility dependency on purchases from IPPs is most appropriately determined through specific Integrated Resource Planning (IRP) proceedings unique to each service territory and set of market conditions.

FINDINGS WITH RESPECT TO CAPITAL STRUCTURES SECTION 111(d)(10)(A)(ii)

15. There is no current need for the Commission to issue additional rules or to adopt a standard regarding Section 111(d)(10)(A)(ii) of PURPA.

16. Subpart (ii) of PURPA Section 111(d)(10)(A) concerning whether the use of highly leveraged capital structures threatens reliability or provides an unfair advantage over utilities, applies only to Exempt Wholesale Generators (EWGs).

17. There is little evidence based on existing IPP projects (both QF and non-QF) that a high degree of leverage has any effect on reliability. There is

little evidence to suggest that the use of highly leveraged capital structures in future EWG projects will cause EWGs to be significantly more likely to operate unsatisfactorily with respect to operational interfaces or reliability, particularly since experience has been increasing and many are subsidiaries of major utilities.

18. Contract terms can be used to help further assure reliability, including requirements that EWG plants meet the same standards as utility plants with respect to dispatchability, maintenance scheduling, power quality, and capacity testing.

19. In some cases, utility reliability may be enhanced by EWG participation, to the extent that an EWG project provides greater system diversification in terms of the number and size of separate generating capacity sources, and the variety of fuel types and suppliers, generating technologies, and high-voltage transmission grid locations.

20. As long as purchasing long-term wholesale power from EWGs results in adequate and reliable service at the lowest reasonable cost, the purposes of PURPA are met. This evaluation should occur within the context of Integrated Resource Planning; specifically the assessment that is required by Commission Rule R8-58(e).

21. The use by EWGs of highly leveraged capital structures employing greater proportions of debt than found in the capital structures of utilities does not necessarily give them an unfair advantage over utilities as long as all relevant risks are evaluated and appropriate provisions are included in the purchased power contract to compensate for risks.

FINDINGS WITH RESPECT TO ADVANCE APPROVAL OR DISAPPROVAL
SECTION 111(d)(10)(A)(iii)

22. There is no current need for the Commission to implement procedures for the advance approval/disapproval of purchased power or to adopt a standard regarding Section 111(d)(10)(A)(iii) of PURPA.

23. Pre-approval of long-term purchase power contracts shifts some utility risk to ratepayers. This would not lead to the efficient use of utility facilities and resources nor would it result in equitable rates.

24. Supply-side and demand-side resources should be subject to symmetric regulatory review within the context of IRP.

25. The evaluation and selection process to which IPPs are subjected should incorporate the same critical factors that the Commission would want to see assessed had the utility, itself, proposed to build a comparable generating unit of the same technology and fuel type.

26. The details of the process by which utilities evaluate and select purchase power options should be that previously established in Commission Rule R8-58(e), as clarified in the pending consideration of the specific guidelines for utility evaluations of purchased power by IPPs set forth in the Commission's Order Adopting Least Cost Integrated Resource Plans issued June 29, 1993, in Docket No. E-100, Sub 64.

FINDINGS WITH RESPECT TO FUEL SUPPLY ADEQUACY
SECTION 111(d)(10)(A)(iv)

27. There is no current need for the Commission to implement a review process to assure fuel supply adequacy or to adopt a standard regarding Section 111(d)(10)(A)(iv) of PURPA.

28. The process by which purchase power options are evaluated and selected should include criteria related to fuel supply adequacy that are reasonable and appropriate, but a separate proceeding or process should not be required.

29. The criteria embodied in a comprehensive assessment should include: (a) the reliability of the project's primary supplier -- its reserves, production and delivery; (b) the reliability of alternative suppliers; (c) the ability to switch suppliers and/or fuel types; and (d) long term prospects for the fuel's market.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1, 2, AND 3

These findings of fact are based upon Section 111 of PURPA, Section 712 of EPACT and the Commission's Order of March 16, 1993, in this docket.

Section 111 of PURPA, as amended by EPACT, sets forth several ratemaking standards in ten paragraphs for consideration by state regulatory authorities. EPACT added four of the paragraphs. The tenth paragraph was added by Section 712 of EPACT and is the subject of the present proceeding. (The other three paragraphs added by EPACT are the subject of a separate, pending proceeding.) Several parties note that this tenth paragraph is different from the others and that it is not very clear. The other paragraphs list specific ratemaking techniques or regulatory policies for states to consider implementing. The tenth paragraph is more in the nature of a list of issues or questions. Thus, there is some disagreement among the parties as to exactly what the Commission is required to do in this proceeding.

CP&L argues that the paragraph establishes only one standard, which standard directs the Commission to perform a general evaluation of four issues. When this one standard is considered in light of the purposes of PURPA, CP&L concludes that the standard will have an effect upon the purposes of PURPA and, therefore, that the standard should be implemented and the general evaluation of the four issues should be made. However, CP&L argues that the Commission is "<u>not</u> required to reach a specific, unqualified, yes-or-no decision on each of the four issues, but only needs to evaluate the issues and express its views." CUCA, on the other hand, argues that the law requires more than "a general philosophical discussion." Cogentrix argues that issuance of non-binding advisory opinions would only create confusion and would be unwise. Cogentrix argues that there are four standards in Section 712 and that the Commission must consider and make a determination as to each of the four standards. In support of its interpretation, Cogentrix points out that subparagraphs (C), (D), and (E) of Section 712 each explicitly refer to subparagraph (A) as containing "standards."

The Commission agrees with Cogentrix that Section 712 of EPACT refers to "standards," in the plural. Therefore, the Commission concludes that there are four standards in Section 712 and that the proper approach in this proceeding is to consider and make a determination as to each of the four.

Section 111(a), 16 U.S.C. 2621(a), provides that nothing therein prohibits any State regulatory authority from determining that it is not appropriate to implement any of the standards. In addition, Section 117 of PURPA, 16 U.S.C. 2627, expressly provides that the Commission has the authority to adopt, pursuant to State law, a standard or rule that is different from any standard established by Section 111. Thus, while the Commission is required to consider the Section 712 standards, it can adopt any standard or rule it has the authority to adopt under State law or decline to adopt any standard at all. The issue before the Commission, therefore, is whether one or more of the Section 712 standards, some other standard, or no standard at all should be adopted.

Section 111(b), 16 U.S.C. 2621(b), requires the determination concerning whether or not it is appropriate to implement the standards in Subsection 111 (d)(10) to be made in writing, based upon findings included in such determination and upon evidence presented at the hearing, and available to the public. The Commission is required to make its determination within one year of the enactment of EPACT, which was signed by the President on October 24, 1993.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 THROUGH 14

Public Staff witnesses Ciliano and Mitnick testified that a utility's risk and cost of capital may increase anytime it expands generating capacity, whether the expansion is through long-term purchases or its own construction projects. They said that since both strategies have inherent risks, the risk associated with long-term purchases of power cannot be looked at in isolation and must be compared with the risk associated with a utility construction project that would provide comparable resources.

They further testified that the potential for increases or decreases in a utility's cost of capital as a result of its decisions whether to buy or build will vary for each utility depending upon (1) the risks associated with the utility constructing its own plant and the way those risks are managed and (2) the risks associated with purchased power contracts that are based upon the contractual arrangements between the lender and the Independent Power Producer (IPP) and between the purchasing utility and the IPP.

In their opinion, utility cost of capital may be affected only when dependence upon long-term wholesale power purchases rises above a utility-specific threshold. They suggested a number of factors that should be considered in making a utility-specific determination of the appropriate level of dependency on purchased power. These include: the terms of existing purchased power contracts (whether take and pay versus take or pay); fuel diversification; the number and size of IPP projects in proportion to utility generating capacity assets; and the quality of IPP project ownership and mechanisms for mitigating problems.

The Public Staff witnesses emphasized that the type and specific terms of a given purchased power contract are very important factors that must be considered in assessing the risk associated with long-term wholesale purchases of power. They concluded that the risk of IPP dependence can be managed through terms of the wholesale power contract that explicitly deal with contingencies such as a large increase in fuel prices, levels of required unit availability, dispatchability, and other operational interfaces with the utility.

Witnesses Ciliano and Mitnick collected data for 66 utilities on IPP purchased power capacity, utility generating capacity and utility senior debt ratings for the years 1987 through 1992. Of the 14 utilities with IPP dependence over 15%, seven of them had at least one bond rating downgrade between 1987 and 1992. However, the ratings rationale of only two of the 14 identified purchased power dependency as a contributory factor, one of which was Virginia Power (rating went from A+ to A). In the case of one utility, Jersey Central Power & Light, the level of dependency rose from less than one percent to 25 percent but its bond rating improved.

The Public Staff witnesses concluded that the financial risk of IPP dependence can be managed, as risk generally is managed in financial portfolios, through diversification - achieving a mix of IPP versus utility owned and operated plants, and a variety of fuel types and suppliers, generating technologies, and IPP ownerships.

CP&L witnesses Smith and Abrams testified that whenever any corporation, whether a regulated utility, an Exempt Wholesale Generator (EWG), or any other type of corporation, increases its debt leverage and reduces its interest coverage, its financial condition will deteriorate and its cost of capital will go up. They said that when a regulated utility depends on long-term power purchases for a significant portion of its generation, credit rating agencies (and other well-informed investors) treat a portion of the purchased power costs as interest on debt, thereby reducing the utility's interest coverage. They said that in recent years several regulated utilities have experienced bond downratings because of their reliance on purchased capacity. They pointed out that when a utility's cost of capital increases, it is likely to result in increased rates for the utility's customers. They also suggested that if a utility's cost of capital increases, there is likely to be a corresponding increase in the cost of debt for any EWG that sells power to the utility, because an EWG's cost of capital is generally "pegged off" the interest rate for the purchasing utility's senior debt.

Duke witness Osborne stated that the purchasing utility's cost of capital will be affected by long-term wholesale power purchases. He stated that the obligation to make a long-term (more than 10 years) stream of payments for capacity makes purchased power similar to debt. Witness Osborne noted that all four major credit rating agencies reflect in their analyses the impact of purchased power contracts on the credit-worthiness of the purchasing utility. He gave examples of several utilities that have been downgraded by rating agencies citing purchased power agreements as a factor in their decisions. Witness Osborne concluded that the proper way to reflect the true economic impact of long-term contracts is to capitalize assets which have been bought or leased over long periods and reflect those contracts on the balance sheet of the purchaser, noting that this is a straightforward, conservative approach.

Witness Osborne further stated that the use of purchased power contracts would not cause retail rates to increase more than rates would increase with utility built capacity as long as purchased power contracts used to meet capacity requirements are the most economical. He stated that an analysis to determine the cost of purchased power should include any risks inherent in puchasing the capacity, particularly the fact that purchased power obligations can increase the purchasing utility's cost of capital. Witness Osborne concluded that as long as all real costs are incorporated into the evaluation, purchased power contracts would not cause retail rates to increase more than rates would increase with capacity built and owned by the utility.

North Carolina Power witness Carney testified that the impact of purchased power on cost of capital is highly dependent upon the specific terms of the purchase contract. Accordingly, the degree of risk shifting and sharing entailed in wholesale power purchases cannot be evaluated in a generic sense, but must be evaluated on a case-by-case basis. Furthermore, he said that the potential impact of purchased power on the cost of capital can only be appropriately assessed when examined in the context of the total cost impact of the decision to purchase power rather than build facilities.

Witness Carney also referred to the down-rating of North Carolina Power's securities by two of the major rating agencies following the implementation of the Company's competitively bid capacity acquision program. He speculated that the down-rating likely would have occurred much earlier if the Company had undertaken a massive construction program in lieu of purchasing capacity. He also indicated that, if the down-rating did have an adverse effect on the Company's cost of capital, the purchased power program helped delay the impact, to the benefit of the Company's customers. Finally, witness Carney concluded that utilities that have made judicious use of all available resource options will find their competitive positions enhanced and thus display a lower overall cost of capital.

Nantahala witness Tucker stated that if purchased power contracts were structured like Nantahala's current supplemental power contract or the rate schedule for purchases from a qualifying facility to allow Nantahala to purchase power as needed, there would likely be no impact on the cost of capital. However, witness Tucker stated that since it is more likely that a contract with an EWG would be structured on a long-term take or pay basis, the purchased power contract could impact the ability and cost of attracting capital. In addition, witness Tucker stated that it would be appropriate to recognize the long-term obligations on Nantahala's balance sheet by capitalizing the power to be made available as an asset and the contract payment stream as a liability. Witness Tucker further stated that Nantahala would contract with an EWG only if the total cost was less than other alternatives; therefore, any increase in consumer rates would be less than had another alternative been chosen.

Westmoreland-LG&E Partners witness Shanker testified that the correct analysis is not to consider the cost-of-capital impact of purchases in isolation, but rather consider how the impact of purchases compares to the impact of other choices, such as building. He believed that the perception of risk relating to the self-build option was greater than the perceived risk of purchases of IPP power. In the final analysis, he believed the Commission will have to judge whether the build or buy option gives the ratepayer the best overall deal in terms of cost, risk and reliability. His testimony on this issue was adopted by Cogentrix witness Dowling.

Witness Wayne S. Leary testified that there is greater risk to the utility in constructing its own generating capacity than in purchasing power from a Non-Utility Generator (NUG), so the potential for decreases in cost of capital are greater when purchasing power from a NUG.

The information available about the cost of capital issue is voluminous and conflicting; yet there is a general consensus that both buying and building strategies have inherent risks. The risk associated with long-term purchases of power cannot be looked at in isolation and must be compared with the risk associated with a utility construction project that would provide comparable resources. This is best accomplished on a case-by-case basis in the context of the Integrated Resource Planning process.

The Commission concludes that NUG project risk can be managed through selection processes, contract negotiations and diversification of a utility's resource portfolio. The Commission already conducts a variety of regulatory proceedings to evaluate utility construction projects, NUG construction projects and a utility's management of the risks associated with those projects. Those regulatory proceedings include IRP investigations, general rate proceedings, fuel proceedings and proceedings for the issuance of certificates approving construction of generating facilities by utilities and NUGs. The imposition of an additional review process would result in a duplication of the Commission's existing regulatory framework and, correspondingly, an inefficient use of Commission and utility resources. Accordingly, there is no current need for the Commission to issue additional rules or to adopt a standard with regard to Section 111(10)(A)(i) of PURPA.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 THROUGH 21

Public Staff witnesses Ciliano and Mitnick testified that there is little evidence based on existing Independent Power Producer (IPP) projects that a high degree of leverage has any effect on reliability. In addition, they testified that there is little evidence to suggest that the use of highly leveraged capital structures in future Exempt Wholesale Generator (EWG) projects will cause EWGs to be significantly more likely to operate unsatisfactorily with respect to operational interfaces or reliability.

They further testified that contract terms can be used to help further assure reliability, including requirements that EWG plants meet the same standards as utility plants with respect to dispatchability, maintenance scheduling, power quality, and capacity testing. They suggested that in some cases utility reliability may be enhanced by EWG participation, to the extent that an EWG project provides greater system diversification in terms of the number and size of separate generating capacity sources, and the variety of fuel types and suppliers, generating technologies, and high-voltage transmission grid locations.

CP&L witnesses Smith and Abrams testified that the use of highly leveraged capital structures gives EWGs a significant advantage over regulated utilities in competing for wholesale customers such as municipalities and cooperatives. They contended that such competitive advantage is unfair, because it is not based on greater efficiency or better performance on the part of EWGs; instead, it is a purely financial advantage, derived from the fact that debt capital is less costly than equity, together with the fact that interest payments on debt are tax-deductible.

Witnesses Smith and Abrams also testified that the use of leveraged capital structures by EWGs threatens reliability. They said that unlike regulated utilities, EWGs have no statutory obligation to serve all customers and have relatively little equity capital invested in their plants; consequently, in the event of severe operating problems, they have a strong financial incentive to abandon a project rather than spending whatever is necessary to correct the problem and make the plant run reliably. CP&L witness Ingersoll testified that regardless of whether or not EWGs use leveraged capital structures, they can have adverse impacts on reliability, customer costs, and the Integrated Resources Planning (IRP) process.

Duke witness Osborne testified that the finanacial structure of an EWG should not impair the operational reliability of an EWG facility. In support of his position, witness Osborne noted that some non-utility generators operate reliably with nearly 100% debt financing. Witness Osborne stated that an EWG can do so because it depends on the strength of the utility's balance sheet and the utility's commitments to make payments to the EWG. He stated that although there are other factors which can affect reliability and should be considered in evaluating purchased power, a utility can insist on contractual provisions which can mitigate most of these risks. Therefore, witness Osborne concluded that the financial structure of an EWG might not by itself threaten reliability.

Witness Osborne stated further that if strong purchased power contracts with creditworthy utilities enable EWGs to borrow 75-90% of their total capital needs and provide a lower cost basis, then any savings should be passed through to the utility and its customers. Witness Osborne contended that EWGs can only use such high leverage because of purchased power contracts which require payments over a period of many years for capacity and energy, thereby effectively transferring financial risk to the utility. He stated that it is this risk which can increase the cost of capital to the utility and which must be included in the analysis of the purchased power alternative. Witness Osborne concluded that an EWG's use of proportionally greater amounts of debt may not provide an unfair advantage so long as all relevant risks associated with the purchased power are evaluated and appropriate provisions are included in the purchased power contracts to compensate for the risks.

NC Power witness Carney testified that concerns over reliability could be mitigated by making reasonable allowances for attrition in subscribing for capacity and by negotiating reasonable terms for fuel and operating costs. He testified that the operating history of NC Power's purchased capacity to date demonstrated that there was little need to be concerned about reliability. He further testified that there is no reason to assume that a lender's due diligence process before it provided financing is deficient in any respect or that it could be enhanced by the addition of an additional layer of regulatory scrutiny.

Nantahala witness Tucker stated that the level of debt of an EWG would not threaten reliability if the transaction was on a long-term, take-or-pay basis because Nantahala's payment obligation would be sufficient to cover the long-term debt obligations of the EWG. Further, witness Tucker stated that it is not clear that the larger debt in the capital structure of an EWG would be an advantage over the purchasing utility. Witness Tucker added, however, that if an advantage did exist for the EWG, because of its capital structure, the advantage would benefit Nantahala's customers.

Westmoreland-LG&E Partners witness Shanker testified that higher levels of debt in IPP capital structures are likely to lead to increased operating efficiency and reliability. Witness Shanker stated that the basic economics of the IPP facility have to persuade investors in highly competitive capital markets that the project is soundly structured and economically viable which in and of itself assures sound financial underpinnings for almost all project-financed undertakings. Furthermore, witness Shanker noted that once the facility is operating, the revenue stream is almost always dependent on operations. He said that in recognition of this, many purchased power agreements have stringent maintenance requirements to assure adequate maintenance and reliability.

Witness Shanker also stated that there is no unfair advantage to IPPs based on their ability to leverage transactions because there is no barrier to a utility's financing a power plant with project finance. He said that the same financing could be equally available to utilities. Witness Shanker added that if such an advantage existed, it would only result in greater economic efficiency, and a net benefit to customers.

Cogentrix witness Dowling stated that wholesale generators have the same, or greater, incentives as utilities to preserve the quality of their assets and reputations. He added that under the typical "take and pay" performance contracts, wholesale generators usually do not get paid if they do not deliver capacity and availability in accordance with contract specification; utilities, on the other hand, may recover the costs of building their own plants whether or not those plants meet the same performance criteria. In addition, witness Dowling stated that project lenders have the strongest of incentives to keep the plant operational, as this is the only way to convince the utility to keep making payments on which the lender is dependent for repayment of its loan.

Witness Wayne S. Leary testified that there is no reason to believe that the capital structure of Non-Utility Generator (NUG) projects offers an unfair advantage or threatens reliability. He said that if there is an advantage, it is with the utilities because there are capital markets available to the utilities that are not available to NUGs.

The Commission observes that the parties hold different views on the issue of whether the use by EWGs of capital structures which employ proportionally greater amounts of debt than the capital strucutres of utilities threatens reliability or provides an unfair advantage for EWGs over such utilities. However, the Commission notes some common views of the majority of the parties.

In general, most of the parties concluded that the reliability of an EWG is not threatened because of the EWG's use of a proportionally greater amount of debt. The parties noted that reliability concerns can be mitigated through a utility's diversification of non-utility power supplies, specific purchased power contract terms and closer scrutiny by lenders of the expected performance of the project. Furthermore, the general view of the parties is that EWGs' use of proportionally greater amounts of debt than utilities does not provide EWGs with an unfair advantage. Even though EWGs may achieve a lower cost basis by the use of proportionally more debt than utilities, at least some of these savings should be passed through to the utility and its customers. It is noted that EWGs can use such high leverage because EWGs depend on the strength of the utility's balance sheet and the utility's commitment to make payments to the EWG through purchased power contracts which require payments over many years, thereby effectively transferring the financial risk to the purchasing utilities. It is further noted that this can increase the cost of capital to the utility and this effect should be included in a utility's analysis of purchased power. The

Commission concludes that the proportionally greater amount of debt in the capital structure of an EWG does not provide it with an unfair advantage as long as all relevant risks are evaluated and appropriate provisions are included in the purchased power contract to compensate for risks.

Accordingly, there is no current need for the Commission to issue additional rules or to adopt a standard with regard to Section 111(d)(10)(A)(ii) of PURPA.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22 THROUGH 26

Public Staff witnesses Ciliano and Mitnick testified that a Commission pre-approval process (for any kind of utility strategic decision) would reduce utility management prerogative, risk, and ratepayer recourse. In addition, it would transfer some utility risk to ratepayers.

They further testified that to a large extent this issue is inherent in the Integrated Resource Planning (IRP) process, and that IRP principles dictate that supply and demand-side resources would be procured in ways that involve symmetric regulatory review. They discussed Commission Rule R8-58 in some detail, noting that subsection (e) explicitly requires an assessment of purchased power resources. They further testified that while IRP in North Carolina does not constitute advance approval of specific utility actions or costs, it is perceived as reducing the utilities' risk of disallowances (or at least providing for better management of that risk) because of the Commission's and intervening parties' greater involvement in the planning process. They concluded that, unless Commission supervised competitive bidding were pursued, purchased power should continue to be assessed in the same way other resources are assessed within the framework of IRP.

CP&L witness Smith testified that the Commission should do all in its power to ensure that long-term power purchases are properly considered and evaluated. He said that steps to be taken should include establishing a mechanism for the advance approval of power purchases; consideration of the importance of stability and reliability in the electric power system when reviewing applications for certificates of convenience and necessity, proposals for retail wheeling or competitive bidding, and similar proposals affecting the future development of the electric power industry; consideration of competitive factors in ratemaking proceedings and IRP proceedings; and encouragement to utilities to adopt rate design innovations for the purpose of meeting competition from unregulated suppliers.

Duke witness Osborne stated that it would be appropriate for the Commission and the utilities to develop procedures for advance approval or disapproval of long-term purchase power contracts. He stated that advance approval would reduce the risk to both the buyer and the seller of purchased power; therefore, they should also reduce the costs of purchased power to the utility customers. He warned, however, that barriers to the use of Exempt Wholesale Generators (EWGs) should not be created by establishing criteria that may not be applicable to all EWG proposals. Duke witnesses Lee and Osborne expressed concern that adoption of complex, specific rules could frustrate or eliminate EWGs. Duke witnesses Lee and Denton noted that the IRP process and rules provide the appropriate avenue to secure reliable and cost-effective power supplies from a variety of possible resources, including purchased power.

North Carolina Power witness Edwards testified that the Company's successful all-source competitive bidding program has resulted in the acquisition of competitively priced long-term wholesale power supplies. He said that in view of the success of the current bidding process, the Company does not currently believe that a pre-approval process is necessary for particular long-term wholesale power purchases resulting from the bidding program. However, he supported advanced approval whenever a utility is ordered or required by a regulatory body or otherwise to contract with a power supplier with which the Company would not have otherwise contracted.

Nantahala witness Tucker testified that advance approval of purchases from an EWG would be consistent with the required advance approval for the construction of generation and would provide protection for the ratepayer. He said that such procedures would reduce risk to the purchasing utility and the EWG.

NCEMC witness Tipps testified that the certification process seemed to be the logical place to review purchased power contracts. He further indicated that an additional approval procedure would merely be duplicative and an unnecessary time- and money-consuming process.

Westmoreland-LG&E Partners witness Shanker testified that a properly structured process for the expeditious review, evaluation, and approval of power purchase agreements between EWGs and utilities should be beneficial to all parties. He stated that such a review could eliminate a utility's concern over possible disallowance of the pass-through of power purchase costs. From the EWG's perspective, it would eliminate the need for "regulatory-out" contract clauses, under which the purchasing utility is relieved of its obligation to make a payment to the seller when the regulatory authority holds that the payment may not be recovered from ratepayers.

Witness Shanker determined that preapproval apparently refers to Commission approval of both the terms of the contract and the pass-through of the purchase costs. He noted that preapproval eliminates the risk of disallowance in this regard. Witness Shanker noted that if the approval process is not streamlined, construction delays may result. He stated that approval should be automatic if (a) the pertinent demand forecast was reviewed as a part of the IRP process and (b) if the choice of the winning project was the result of a state-approved bidding process.

Cogentrix witness Dowling opposed procedures for advance approval or disapproval of power purchases. He recommended that the Commission retain authority over projects on a case-by-case basis rather than implement generic procedures which may fail to consider the particulars of a specific agreement or to take into account the IRP process. He said that an IRP process should determine the appropriate amount of capacity, the fuel type and operating characteristics of additional generation needed, and the time at which such capacity is needed. He suggested that when complemented with a competitive bidding process, the IRP process should provide a mechanism which would take the place of a generic advance approval procedure and could allow case-by-case approvals to be obtained sufficiently fast. Witness Dowling stated, however, that if the Commission decides to implement generic procedures, it should include preapproval for utility pass-throughs of purchase power payments.

Witness Wayne S. Leary testified that the IRP process is adequate to identify utility capacity requirements, but should be accompanied by a competitive acquisition system for capacity requirements. However, he said that the additional regulations necessary to implement procedures for advance approval or disapproval of the purchase of long-term wholesale power supplies would be unwarranted.

The Commission is of the opinion that a pre-approval process shifts a portion of the responsibility for strategic decision-making to the Commission and shifts a corresponding share of the risk of disallowance associated with such strategic decisions to ratepayers. Accordingly, the Commission should exercise caution in mandating the pre-approval of decisions traditionally left to utility management. The Commission is also influenced by the need to limit the regulatory delay that could result from a pre-approval process.

Moreover, the Commission rules governing Integrated Resource Planning are designed to provide the Commission and other interested parties with an opportunity to review utilities' strategic decision-making processes with regard to their long-range resource plans. Rule R8-58(e) requires utilities to perform detailed assessments of reasonably available purchased power resources and to document the assumptions relied upon in evaluating those resources. The Commission periodically investigates the IRPs of utilities, consistent with the requirements of those rules, with the objective of ensuring that utilities have developed an appropriate combination of reliable resource options (including purchased power) for meeting anticipated demands in a cost effective manner. The Commission has analyzed utility assessments of both solicited and unsolicited purchase power proposals during the course of previous IRP investigations. The IRP process has worked extremely well to date and the Commission does not believe that it is necessary or in the public interest to implement a pre-approval process at this time.

In furtherance of the Commission's IRP objectives, the Commission recently proposed a set of guidelines for the evaluation of unsolicited Non-Utility Generator (NUG) proposals. Those guidelines are currently the subject of public comment and review in the final phase of the Commission's most recent IRP investigation, Docket No. E-100, Sub 64. The NUG guidelines, as currently proposed, would require a utility to periodically file its methods, assumptions and supporting rationale as well as a description of the process relied upon in evaluating unsolicited NUG proposals.

Finally, the question remains as to how a pre-approval process would assist in carrying out the purposes of Title I of PURPA. It is arguable that any reduction in regulatory risk that results from the implementation of a pre-approval process would encourage cost effective long-term wholesale purchases, rather than certain less efficient resource options, thus conserving energy and encouragaging equitable rates through the most efficient use of utility facilities and resources. However, it is equally plausible that pre-approval would simply result in a preference for "less risky" pre-approved wholesale purchases to the exclusion of more reasonably priced resources, including conservation options.

The Commission, in its decision not adopt a pre-approval process at this time, seeks to ensure that all resource options are afforded an equal competitive opportunity, consistent with the requirements of Commission Rule R8-58. The

Commission's reliance upon the existing IRP process, as modified by the proposed guidelines for the evaluation of unsolicited NUG proposals, is designed to foster a competitive market place for purchased power, thereby encouraging conservation, the efficient use of utility facilities and resources, and equitable rates to customers, consistent with the goals of Title I of PURPA.

In summary, the Commission concludes that mandatory advance approval of purchased power contracts is not necessary at this time. The review of purchased power resources should continue to be handled through the IRP process. Accordingly, there is no current need for the Commission to implement procedures for the advance approval/disapproval of purchased power supplies as envisioned in the standard enunciated in Section 111(d)(10)(A)(iii) of PURPA.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27, 28 AND 29

Public Staff witnesses Ciliano and Mitnick testified that if the Commission opted to review the process by which Independent Power Producer (IPP) contracts were selected, then it would follow that the Commission could satisfy itself that the process by which purchased power options are evaluated and selected was reasonable and appropriate, including criteria related to fuel supply adequacy. They testified that a separate proceeding or process, however, should not be required.

They suggested that the criteria embodied in a comprehensive assessment should include: (a) the reliability of the project's primary supplier -- its reserves, production and delivery; (b) the reliability of alternative suppliers; (c) the ability to switch suppliers and/or fuel types; and (d) long-term prospects for the fuel's market.

CP&L witnesses Smith and Yarger testified concerning the risks associated with each of the fuel sources most often used by Exempt Wholesale Generators (EWGs) -- gas, oil, and coal. They noted that the loss of a single fuel supplier may have much more disastrous consequences for an EWG than for a regulated utility, because utilities have numerous fuel suppliers and generation sources, whereas the typical EWG has only a small number of fuel suppliers and generating plants, or sometimes only a single supplier and a single plant. Witness Smith testified that whenever any purchaser buys power from a non-utility supplier, it is critically important that the seller have reasonable assurances of fuel supply adequacy. He stated that CP&L is prepared for the Commission to review the fuel supply adequacy of the entities from which it purchases power.

Duke witness Osborne testified that it is appropriate to require a reasonable assurance of fuel supply adequacy, noting the importance of fuel supply in assessing a source of reliably capacity. Witnesses Osborne and Lee both noted that the assessment of what constitutes a reasonable assurance of fuel supply adequacy can best be done on a case-by-case basis.

North Carolina Power witness Edwards testified that the Company's fuel supply evaluation and contract terms provide a reasonable assurance of fuel supply adequacy. For instance, the Company's bidding program includes consideration of fuel supply as a nonprice issue. Further, early in the development of a Non-Utility Generator (NUG) project, the developer is required to submit its fuel supply transportation plans for the company's review and provide documentation sufficient to verify the contract's existence. The contract with the developer also requires the maintenance of sufficient fuel inventory levels to provide reasonable operational availability and provides significant economic incentives to ensure the facility does not fail to generate due to nonavailability of fuel. Witness Edwards indicated that the Company had no evidence that the adequacy of fuel supplies poses a significant concern for projects currently under contract. He also concluded that the addition of a long-term fuel supply contract requirement may result in less economic projects from the utility's perspective.

Nantahala witness Tucker believed that adequate fuel supplies should be a condition for approval of a long-term wholesale purchased power contract because without an available fuel supply the capacity being contracted for has no value. Witness Tucker noted that Nantahala would assure itself that a supplier could provide power reliably prior to entering into a long-term purchased power contract.

Cogentrix witness Dowling testified that regulatory review of the adequacy of fuel supply generally is not necessary for project-financed wholesale generators because suppliers of capital already scrutinize such arrangements carefully before agreeing to finance the projects. He further testified that any regulatory examination of system-wide fuel mix risk is best performed in the integrated resource planning process, or in the formulation of the request for proposals if competitive bidding is pursued.

Westmoreland-LG&E Partners witness Shanker testified that the real issue is not that some consideration is needed of fuel supply, but whether or not it is incumbent upon state regulators to perform that function. Witness Shanker indicated that competitive processes will inspire the most efficient options in meeting necessary fuel requirements. Further, he said that the utility's fuel supply requirements for the IPP will be explicitly stated in specific contract provisions to demonstrate adequacy of fuel supplies commensurate with contact obligations, which will be scrutinized by both developers and project lenders and investors. Witness Shanker concluded that an additional layer of Commission oversight is unnecessary.

NCEMC witness Tipps testified that while it is important to assure that power sellers will have an adequate supply of fuel available, there are certain problems that will interfere with any effort by the Commission to require an adequate fuel supply as a condition for advance approval of a power purchase agreement. In particular, NCEMC is required to give Duke eight years' notice before bringing another power source into Duke's service area, and a seller could not reasonably be expected to obtain a firm-price fuel supply contract eight years in advance.

Witness Wayne S. Leary testified that assurances of fuel supply are already a consideration by developers, lenders and other participants in their evaluation of NUG projects, so no additional standards are needed to require assurances of fuel supply.

The Commission previously concluded herein that mandatory advance approval of long-term wholesale power supply is unnecessary at this time. The Commission also concluded herein that the review of purchased power resources should continue to be handled through the IRP process. Fuel supply adequacy is an integral part of a purchased power supply contract and it need not be isolated for special review. Instead, fuel supply adequacy should be analyzed simultaneously with the Commission's review of the underlying long-term wholesale power supplies during the course of an IRP proceeding.

Moreover, the evaluation of fuel supply adequacy as a condition of pre-approval presupposes that the Commission will adopt a pre-approval process for particular long-term wholesale power purchases. As discussed previously, the Commission declines to implement procedures for the advance approval/disapproval of particular long-term wholesale power supplies at this time.

Accordingly, there is no current need for the Commission to implement a review process to assure fuel supply adequacy as envisioned in the standard set forth in Section 111(d)(10)(A)(iv) of PURPA.

IT IS, THEREFORE, ORDERED that this Order be issued as the Commission's consideration and determination pursuant to Section 712 of EPACT and Section 111(d)(10) of PURPA.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-100, SUB 47

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of the Regulatory Framework for Natural Gas Utilities	)))	ORDER MODIFYING PROCEDURES FOR ACCESS TO GAS PURCHASE CONTRACTS

BY THE COMMISSION: On February 21, 1989, the Commission issued an Order in this docket establishing certain procedures for access to and review of the gas purchase contracts of the natural gas local distribution companies (LDCs).

Subsequent to that Order, G.S. 62-133.4 was enacted effective July 8, 1991. This statute provides for gas cost adjustment proceedings for LDCs and provides for annual reviews to compare each LDC's prudently-incurred gas costs with costs recovered from customers during the test period.

The Commission recently held the first annual review of gas costs for Piedmont Natural Gas Company, Inc., in Docket No. G-9, Sub 329. In that proceeding, the Public Staff presented testimony that it needs greater access to gas purchase contracts than that allowed by the Commission's February 21, 1989, Order, in order to conduct the prudency investigation called for by the new statute. The Public Staff recommended that new procedures be adopted. Piedmont presented testimony opposing the Public Staff's recommendation. The Panel of Commissioners hearing the Piedmont annual review proceeding concluded that procedures for access to gas purchase contracts should be reviewed in light of the new statute G.S. 62-133.4, but that the review should take place in a generic proceeding since it involves all LDCs, not just Piedmont.

On February 15, 1993, the Commission issued an Order in this docket providing that the procedures for access to gas purchase contracts should be reviewed in light of the new statute G.S. 62-133.4. The Commission provided for all parties to file comments addressing both whether present procedures should be modified and how the Commission should proceed.

Comments were filed by the Public Staff, the Attorney General, Piedmont, Public Service, NCNG, and CUCA. None of the parties asked for an evidentiary hearing. By Order of March 18, 1993, the Commission scheduled an oral argument to allow all parties to respond to comments made by other parties and to present their arguments directly to the Commission and to answer Commission questions. Oral argument was held as scheduled.

The Commission has carefully considered the written comments and oral arguments of all parties. The procedures established by the Commission's February 21, 1989, Order in this docket were designed to "allow the Public Staff and the Attorney General ready and convenient access to the gas purchase contracts in questions and [to] ensure the confidentiality of those contracts to the greatest extent possible." The procedures were a balance designed to accommodate both the Public Staff's and the Attorney General's need for access and the LDCs' need for confidentiality. The Commission continues to believe that the previously established procedures--with the one change ordered herein--strike the best possible balance and should be continued in effect.

The one change relates to the requirement (found in the protective agreements entered to implement the February 21, 1989, Order) that the Public Staff and the Attorney General execute an affidavit within 30 days after each general rate case stating that handwritten notes concerning gas purchase contracts which were made since the LDC's last general rate case have been destroyed. Since the Public Staff's and the Attorney General's review of gas purchase contracts is now conducted for purposes of the annual reviews of gas costs as well as general rate cases, it is appropriate to change this requirement. In order to prevent unnecessary duplication of notetaking, the Commission concludes that the requirement to destroy notes should be related to the term of the particular contract to which the notes relate. Therefore, the Commission concludes that the protective agreements required by the Commission's February 21, 1989, Order should not require that the Public Staff or the Attorney General destroy their handwritten notes until after the term of the contract to which the notes relate has expired.

With respect to the arguments of CUCA concerning its access to gas purchase contracts, the Commission simply notes that both the Commission's February 21, 1989, Order and the present proceedings address the Public Staff's and Attorney General's access to gas purchase contracts. Neither was intended to address the discovery rights of other intervenors. The discovery rights of other intervenors will be dealt with on a case-by-case basis as particular issues arise.

IT IS, THEREFORE, ORDERED that the procedures for access to gas purchase contracts established by the Commission on February 21, 1989, in this docket shall remain in effect with the one change ordered herein, i.e., that the protective agreements executed to implement the procedures shall not require that the Public Staff or the Attorney General destroy their handwritten notes until after the term of the gas purchase contract to which the notes relate has expired.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of April 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Commissioner Hughes dissents as to the change in procedures ordered herein. He would leave the previously established procedures unchanged.

DOCKET NO. G-100, SUB 57

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Implement G.S. 62-158 Which Authorizes the Commission to Order a Natural Gas Local Distribution Company to Create a Special Natural Gas Expansion Fund	))))))	ORDER ESTABLISHING NEW ACCOUNTING PROCEDURES UNDER G.S. 62-48(b)

BY THE COMMISSION: G.S. 62-48(b) authorizes the use of supplier refunds received by local distribution companies (LDCs) to pay for the Commission's legal counsel appearing before federal courts and agencies and related travel expenses of the Commission staff and the Public Staff. For years, the Commission has retained legal counsel in Washington, D.C. to represent the Commission before the Federal Energy Regulatory Commission and federal courts. The Commission staff and the Public Staff incur travel expenses from time to time assisting Washington counsel. The Commission pays for these expenses and periodically calls upon the LDCs to reimburse the Commission proportionately out of their supplier refunds. G.S. 62-48(b) authorizes the Commission to establish procedures for the LDCs to set aside reasonable amounts of supplier refunds to pay for Washington counsel and related travel.

The Commission issued an Order regarding the handling of supplier refunds by LDCs in this docket on March 12, 1992. The Order was prompted by the new expansion fund legislation, G.S. 62-158. Among other things, the Order provides for each LDC to hold final supplier refunds that it proposes to include in an expansion fund in a separate bank account pending further order of the Commission. The Commission continued this procedure when it issued its Order in this same docket on April 9, 1992, adopting rules to implement G.S. 62-158. Neither of these Orders addressed the use of supplier refunds for Washington counsel.

In Docket No. G-21, Sub 306, a proceeding to establish an expansion fund for NCNG, the Commission recently heard testimony from the Public Staff recommending that the NCNG's accounting procedures be changed to ensure that the Commission's Washington counsel is paid from supplier refunds as provided by G.S. 62-48(b). Since this recommendation affects all LDCs, the Commission decided to reopen the rulemaking proceeding in order to establish appropriate procedures to coordinate the use of supplier refunds for Washington counsel pursuant to G.S. 62-48(b) with the use of supplier refunds for expansion funds under G.S. 62-158. In order to provide for the use of supplier refunds pursuant to G.S. 62-48(b), the Commission will modify the procedures established by the March 12, 1992, and the April 9, 1992, Orders in this docket as follows.

The Commission has determined, based on its past annual expenses, that \$60,000 is an appropriate amount to be kept on hand for purposes of G.S. 62-48(b). This amount shall be divided proportionately among the four LDCs based on the most recent annual level of sales and transportation of gas. NCNG's share is \$16,200; Public Service's share is \$19,800; Piedmont's share is \$22,800; and North Carolina Gas's share is \$1,200. Each LDC shall establish a separate reserve account for purposes of reimbursing the Commission for expenses pursuant to G.S. 62-48(b). Each LDC shall credit the reserve account directly with the next final supplier refunds it receives, up to the dollar amount stated above. Following each reimbursement to the Commission, each LDC shall bring its account balance back to the level shown above with the appropriate amount of supplier refunds next received. The LDCs shall accrue interest on this account at the same rate an in the same manner as interest is accrued on the deferred account. No gas costs savings or other monies shall be credited to this account. All supplier refunds other than those necessary to fund this account shall be handled pursuant to the provisions of the March 12, 1992, and the April 9, 1992, Orders in this docket. Those Orders provide that supplier refunds held for inclusion in an expansion fund shall be kept in a separate bank account with interest at the prevailing rate, and that supplier refunds not held for an expansion fund shall be held and refunded according to past practice.

IT IS, THEREFORE, ORDERED that the local distribution companies shall account for supplier refunds to pay for the Commission's legal counsel appearing before federal courts and agencies and related travel expenses of the Commission staff and the Public Staff in the manner set forth herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. T-100, SUB 18

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition to Revise Commission Rule R2-37	) ORDER AMENDING RULE R2-37) AND GRANTING GROUP 19) COMMON CARRIER AUTHORITY) TO CERTAIN DESIGNATED CARRIERS

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, January 26, 1993, at 9:30 a.m.

BEFORE: Chairman William W. Redman, Jr., Presiding; Commissioners Sarah Lindsay Tate, Robert O. Wells, Julius A. Wright, Charles H. Hughes, Laurence A. Cobb, and Allyson K. Duncan

APPEARANCES:

For the Tobacco Transporters Association:

David H. Permar, Attorney at Law, Hatch, Little & Bunn, 327 Hillsborough Street, Raleigh, North Carolina 27603

For the Using and Consuming Public:

Robert B. Cauthen, Jr., Staff Attorney, Public Staff, North Carolina Utilities Commission, P. O. Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On October 19, 1988, the Commission issued an Order in Docket No. M-100, Sub 116, interpreting Rule R2-37 to include unmanufactured tobacco in Group 1, general commodities. General commodities, as defined in Group 1 in Rule R2-37, includes property the transportation of which does not require special equipment for hauling, loading, or unloading, or any special or unusual service in connection therewith. The Commission determined that unmanufactured tobacco does not require special handling or equipment for loading and transporting and that tobacco is transported much the same as other commodities transported by carriers of general commodities.

On March 16, 1992, counsel for the Tobacco Transporters Association (TTA) filed a petition with the Commission to revise Rule R2-37 by adding the following language to the description of Group 1, general commodities: "This group does not include unmanufactured tobacco and accessories as defined in Group 19." The petition also requested that all certificated carriers hauling Group 19, unmanufactured tobacco and accessories, under Group 1, general commodities, authority be issued Group 19 authority.

On March 18, 1992, the Public Staff filed comments on the TTA's petition and a motion that the Commission institute a rulemaking proceeding to consider the elimination of Group 19, unmanufactured tobacco and accessories, as a defined commodity group. In its comments, the Public Staff stated it agrees with the Commission's determination in Docket No. M-100, Sub 116, and that the solution proposed by the TTA is not in the public interest and the elimination of Group 19 as a defined commodity group is a more appropriate solution.

On September 1, 1992, counsel for the TTA filed a request to schedule a hearing in this docket to consider both the TTA's petition and the motion of the Public Staff.

On October 22, 1992, the Commission issued an Order scheduling a hearing in this docket to consider the TTA's petition and the motion of the Public Staff. The Order also directed the TTA to prefile testimony not later than December 7, 1992, and the Public Staff and other interested parties to file its testimony as well as petitions to intervene not later than January 6, 1993. The Order further directed that a copy of the Order be published in the Truck Calendar of Hearings and mailed to all parties of record in the docket and all motor carriers holding general commodities and unmanufactured tobacco authority issued by this Commission.

On January 6, 1993, English Trucking Company, Inc. (English) and C. N. Trucking Company (C. N. Trucking) filed a Petition to Intervene and Motion to Limit Scope of Proceeding in this docket. English and C. N. Trucking both transport unmanufactured tobacco under their respective general commodities authority and have no interest in this proceeding unless there is a possibility that Commission Rule R2-37 be amended to restrict their authorities against transportation of unmanufactured tobacco. Therefore, English and C. N. Trucking requested that the Commission limit the scope of the hearing to the specific proposals made by the TTA and the Public Staff.

On January 21, 1993, the Commission issued an Order granting the joint petition of English and C. N. Trucking to intervene and limiting the scope of the proceeding in this docket to a consideration of the petition of the TTA and the motion of the Public Staff. No other carriers or shippers filed petitions to intervene.

The following witnesses prefiled testimony and appeared and testified before the Commission on behalf of the TTA: Doug Leckie, Chief Executive Officer of Burton Lines, Inc. (Burton); Vance T. Forbes, Jr., President of Forbes Transfer Company, Inc. (Forbes); Fred G. Bond, Chief Executive Officer of the Flue-Cured Tobacco Cooperative Stabilization Corporation (Stabilization Corporation); and Elbert L. Peters, President and Chief Executive Officer of the North Carolina Trucking Association (NCTA).

The Public Staff presented the testimony of James C. Turner, Director of the Transportation Rates Division, Public Staff.

The TTA attached to its petition a list of nine general commodity carriers who are transporting unmanufactured tobacco and accessories without Group 19 authority. The TTA's petition requests that these carriers be issued Group 19 authority on a grandfather basis. At the beginning of the hearing, the TTA made a motion to add C. N. Trucking to this list. Without objection, the motion was allowed.

On February 15, 1993, an affidavit was filed by Mr. G. E. Martin, Jr., President, Burton Lines, Inc., concerning a question from the Commission at the hearing regarding whether Group 19 includes the transportation of machinery used in the manufacturing of cigarettes.

Based upon the petitions and motions filed herein, the testimony and exhibits offered at the hearing, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. Burton and Forbes are two motor carriers holding common carrier certificates issued by this Commission authorizing the transportation of Group 19, unmanufactured tobacco and accessories, Group 1, general commodities, and other specified commodities regulated by this Commission.

2. The TTA is a voluntary association of 15 carriers of unmanufactured tobacco and accessories participating in tariff eight of the North Carolina Trucking Association. The TTA functions as a rate committee and also files joint protests to applications for new authority filed with the Commission.

3. The Stabilization Corporation is a tobacco growers' cooperative owned and operated by flue-cured tobacco growers. Its purpose is to assure the producers of tobacco in the flue-cured area a stabilized market by placing a minimum price on each lot or sheet of tobacco offered for sale in the auction system. The Stabilization Corporation is a shipper of tobacco and supports Group 19 as a separate commodity group.

4. The NCTA is a non-profit trade association representing the general and specific interests of its members engaged in the transportation of property by motor vehicles in North Carolina. One purpose of the NCTA is to act as a tariff publishing agent for members who participate in North Carolina intrastate commerce. Currently, the NCTA publishes joint tariffs for seven commodity groups, including unmanufactured tobacco. The NCTA supports Group 19 as a separate commodity group.

5. The tobacco shippers consist of the large manufacturers of domestic tobacco products, such as R. J. Reynolds and American Tobacco, and dealer companies that purchase tobacco for resale to foreign and domestic manufacturers, such as A. C. Monk, Universal Leaf, and the Flue-Cured Tobacco Cooperative Stabilization Corporation.

6. General commodities are defined as property the transportation of which does not require special vehicles or special equipment for hauling, loading, or unloading or any special or unusual service in connection therewith. In its Order in Docket No. M-100, Sub 116, dated October 19, 1988, this Commission determined that the transportation of unmanufactured tobacco does not require special vehicles, special equipment, or special service, and thus, unmanufactured tobacco was included within the definition of Group 1, general commodities. Consequently, the TTA began filing protests to all Group 1, general commodities, appli- cations. Ninety percent of the applicants voluntarily amended their applications to exclude unmanufactured tobacco. These protests have cost the TTA over $60,000.00 in legal expenses.

7. The tobacco marketing season and the period in which unmanufactured tobacco is transported occurs primarily in the months of July, August, and September.

8. The additional trailers which the shippers require the unmanufactured tobacco carriers to make available during the tobacco marketing season are generally unused during the off-season.

9. The financial health of motor carriers in general and tobacco carriers in particular has been declining over the past 10 years. For calendar years 1989 through 1991, the operating ratio for intrastate, unmanufactured tobacco, cost study carriers was in excess of 109%.

10. Since 1988, the shippers of unmanufactured tobacco have imposed additional requirements on unmanufactured tobacco carriers. They now require a minimum trailer length of 45 feet, a third tarp, and they require the carriers to allow the use of their trailers for the storing of tobacco.

11. During the tobacco marketing season, 20,000,000 pounds of tobacco per day are sold and must be transported to the redrying facilities. This marketing and transportation requires a cooperative effort by farmers, warehouse operators, labor contractors, shippers, and tobacco carriers.

12. The tobacco shippers desire adequate amounts of equipment available to ship all tobacco sold on the date of sale to the redrying facilities and that the carriers have uniform rates for the services provided.

13. Contrary to the conclusion previously reached by the Commission in Docket No. M-100, Sub 116, the evidence in this case establishes that the transportation of unmanufactured tobacco requires specialized equipment and service. Tobacco is a highly perishable commodity at the point of sale and must be transported rapidly and efficiently to a tobacco processing plant. The trailers are specially modified with customized side kits and tailgates so as to hold an oversized load of farmer's bales of specified dimension. Unmanufactured tobacco transportation requires special permits from the Department of Transportation for the oversized loads. In addition, three tarpaulins which are unique to tobacco transportation are required to cover the load. Each trailer must be equipped with shipper-specified ropes and straps. Tobacco carriers also supply extra quantities of flatbed trailers to allow the shippers to use their trailers as temporary storage while the tobacco is awaiting processing at the shippers' redrying plants.

14. The general commodity carriers listed on Exhibit A attached to this Order are also transporting unmanufactured tobacco and accessories.

15. In his affidavit filed on February 15, 1993, Mr. G. E. Martin, Jr., President of Burton Lines, Inc., addressed the question of whether or not Group 19 includes the transportation of machinery used in the manufacturing of cigarettes. Mr. Martin stated that during his 35 years in the transportation of unmanufactured tobacco, the term "manufacturing" as used in Group 19 has always been interpreted to include the manufacturing process through redrying or reconstruction of tobacco and tobacco products but not including the manufacturing of tobacco cigarettes and other finished tobacco products. Burton transports many commodities such as paper, filter materials, and machinery used

for manufacturing cigarettes to and from cigarette manufacturing plants, however, these commodities are transported and rated under Burton's general commodities authority and tariff.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The transportation of unmanufactured tobacco requires specialized equipment and special services in connection therewith as that phrase is used in Group 1 of Commission Rule R2-37. This Commission reached a contrary conclusion in its Order dated October 19, 1988, in Docket No. M-100, Sub 116. However, the decision in that docket was made without the benefit of an evidentiary hearing and the more fully developed record contained in this docket. The hearing in this docket brought to the Commission's attention the unusually shaped and oversized loads, requiring special permits, which the carriers use for transporting unmanufactured tobacco. The hearing also established the unusually large number of trailers which the unmanufactured tobacco carriers must provide to the shippers for storage, as well as other specialized service requirements of the shippers. All of these factors contribute to a contrary conclusion in this proceeding.

As set forth in G.S. 62-152.1, it is the policy of the State of North Carolina to fix uniform rates for the same or similar services by carriers of the same class. The evidence in this docket indicates that both the shippers and the carriers desire a separate commodity grouping for unmanufactured tobacco in order to facilitate joint ratemaking, which will in turn tend to encourage uniform rates.

G.S. 62-261(11) provides, "The Commission may from time to time establish such just and reasonable classifications of groups of carriers included in the term 'common carrier by motor vehicle' or contract carrier by motor vehicle as the special nature of the service performed by such carriers shall require; and such just and reasonable rules, regulations, and requirements, consistent with the provisions of this article, to be observed by such carriers so classified or grouped as the Commission deems necessary or desirable in the public interest." Therefore, the Commission concludes that maintaining Group 19, unmanufactured tobacco, as a commodity group separate and apart from Group 1, general commodities, is necessary and desirable in the public interest.

It is apparent that the dispute and confusion which has arisen in this docket is primarily the result of uncertainty in determining what is meant by the word "special" as used in Group 1 of Rule R2-37. The problem can best be resolved by adding the following language to Group 1: "This group does not include unmanufactured tobacco and accessories as defined in Group 19."

In order to avoid any further confusion, the Commission also concludes that Group 19 should be amended to define the term "manufacturing" as used in Group 19 to include the manufacturing process through redrying or reconstruction of tobacco and tobacco products but not including the manufacturing of tobacco cigarettes and other finished tobacco products.

Based upon present and prior operations, the public convenience and necessity require that the general commodity carriers listed on Exhibit A be granted Group 19 authority in addition to existing authorized transportation service. Any other general commodity carrier who can prove to the satisfaction of the Commission that it has been transporting unmanufactured tobacco can petition the Commission to be granted Group 19 authority.

IT IS, THEREFORE, ORDERED:

1. That Commission Rule R2-37 be, and is hereby, amended by adding the following language to Group 1, general commodities: "This group does not include unmanufactured tobacco and accessories as defined in Group 19." Group 19, unmanufactured tobacco and accessories, is also amended as follows: "This group includes the transportation of tobacco leaf, unmanufactured tobacco scraps or stems in sheets, baskets, hogsheads, tierces, boxes, or bales, including cooperage stock, tobacco baskets and tobacco sheets, to be used in the manufacturing, processing, storage, marketing, and transporting of tobacco and tobacco products <u>through redrying or reconstruction,</u> including other accessories, materials, and supplies, and equipment used, or useful in the manufacturing, processing, storage, marketing, and transporting of tobacco or tobacco products <u>through redrying or reconstruction,</u> or substitutes for any of said articles."

2. That the general commodity carriers listed on Exhibit A attached hereto are hereby authorized to transport Group 19, unmanufactured tobacco and accessories, as defined in Commission Rule R2-37 and that their certificates be amended accordingly.

3. That a copy of this Order shall be published in the Commission's Truck Calendar of Hearings and copies shall be mailed to all parties of record in this docket and all motor carriers holding general commodities and unmanufactured tobacco authority issued by this Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Commissioner Laurence A. Cobb dissents.

EXHIBIT A

NORTH CAROLINA INTRASTATE GENERAL COMMODITY
CARRIERS GRANTED GROUP 19 AUTHORITY

Embers Express Trucking
Company, Inc.
P. O. Box 937
Lake City, S. C. 29560
Certificate No. C-1322

English Trucking Company,
Inc.
1072 Nine Mile Road
Richlands, N. C. 28574
Certificate No. C-1413

K. M. Pulley Trucking Company,
Inc.
3101 Ridgecrest Drive
Rocky Mount, N. C. 27803
Certificate No. C-1367

L. J. Rogers, Jr., Trucking,
Inc.
Route 5, Box 77
Mebane, N. C. 27302
Certificate No. C-1863

B-Freight Line, Ltd.
3402 Barnette Lane
Kinston, N. C. 28501
Certificate/Permit No. CP-82

J. Clint Fleming, Inc.
P. O. Box 1002
Danville, Virginia 24543
Certificate No. C-1282

Epes Hauling, Inc.
3400 Edgefield Court
Greensboro, N. C. 28409
Certificate No. C-1943

Tobacco Contractors, Inc.
800 Asphalt Road
Kinston, N. C. 28501
Certificate No. C-1920

Great Coastal Express, Inc.
P. O. Box 24286
Richmond, Virginia 23224
Certificate No. C-1453

McGee Trucking Company, Inc.,
d/b/a C. N. Trucking Company
P. O. Box 393
Wilson, N. C. 27894
Certificate No. C-1432

DOCKET NO. P-100, SUB 72

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Investigation to Consider Whether Long Distance Telephone Service Should be Allowed in North Carolina and What Rules and Regulations Should be Applicable to Such Competition if Authorized
) ORDER ADOPTING POLICY AND GUIDELINES ON PENALTIES FOR ILLEGAL INTRASTATE OPERATIONS BY INTEREXCHANGE CARRIERS

BY THE COMMISSION: In 1984, the General Assembly passed G.S. 62-110(b) empowering the Commission to authorize long distance competition as follows:

> (b) The Commission shall be authorized to issue a certificate to any person applying to the Commission to offer long distance services as a public utility as defined in G.S. 62-3(23)a.6., provided that such person is found to be fit, capable, and financially able to render such service. . .

G.S. 62-3(23)a.6 defines a telecommunications public utility as a "person. . . owning or operating in this State equipment or facilities for: [c]onveying or transmitting messages or communications by telephone or telegraph, or any other means of transmission, where such service is offered to the public for compensation."

These provisions must be read together with G.S. 62-110(a) which provides:

> . . .[N]o public utility shall hereafter begin the construction or operation of any public utility plant or system or acquire ownership or control thereof, either directly or indirectly, without <u>first</u> obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction, acquisition, or operation. . . (Emphasis added).

The general import of these provisions is that it is illegal for a public utility to provide or solicit to provide service <u>prior</u> to certification. <u>See</u> <u>In Re NCN Communications, Inc.,</u> Docket No. P-214, Order to Cease and Desist, Issued July 9, 1990.

In 1985, in Docket No. P-100, Sub 72, the Commission, pursuant to G.S. 62-110(b), authorized the provision of competitive intrastate long distance service. Generally speaking, the Commission requires documentation of the following before a certificate will be issued:

1. Fitness of the applicant to provide the service;

2. Financial ability of the applicant to provide the service;

3. Technical ability of the applicant to provide the service;

4. The nature of the proposed service to be offered;

5. A clear definition of the geographical area and routes to be initially served by the applicant;

6. Tariffs reflecting the services to be offered, including rates and regulations applicable to each service;

7. Minimal rate justification to the extent necessary to establish that the proposed rates are competitive;

8. A plan subject to waiver for switchless resellers, rebillers, or aggregators detailing the applicant's proposed methodology for determining the monthly quantity of intrastate (interLATA and intraLATA) access minutes on its system in North Carolina;

9. A plan detailing the applicant's proposed methodology for determining the unauthorized intraLATA conversation minutes occurring on its facilities each month, or, if the applicant is a switchless reseller, rebiller or aggregator, a letter from the underlying carrier;

10. A plan detailing the applicant's proposed accounting methodology and necessary allocation procedures required to provide to the Commission the North Carolina intrastate jurisdictional financial operating results of the company;

11. A statement that the applicant agrees to abide by all applicable rules and regulations of the Commission and the findings, conclusions, terms, and conditions set forth in pertinent Commission orders; and

12. The application shall be verified and sponsored by an appropriate offer or representative of the applicant who is familiar with the information set forth therein.

Since 1985, the Commission has certified nearly 60 interexchange carriers (IXCs), with nearly 20 applications pending at this time.

Unfortunately, not all of the companies soliciting or operating in this State on an intrastate basis have obtained certificates. This is the problem of the uncertificated IXC. The question posed in this matter is how to deal with such IXCs--more specifically, should the Commission continue with a policy of requiring comprehensive, individualized refunds from such companies or should the Commission adopt some other policy, for example, one emphasizing fines and penalties?

The statutory basis for requiring refunds stems from G.S. 62-139 which reads as follows:

> (a) No public utility shall directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed by the Commission, nor shall any person receive or accept any service from a public utility for a compensation greater or less than that prescribed by the Commission.

> (b) Any public utility in the State which shall willfully charge a rate for any public utility service in excess of that prescribed by the Commission, and which shall omit to refund the same within 30 days after written notice and demand of the person overcharged, unless relieved by the Commission for good cause shown, shall be liable to him for double the amount of such overcharge, plus a penalty of ten dollars ($10.00) per day for each day's delay after 30 days from such notice or date of denial or relief by the Commission, whichever is later. Such overcharge and penalty shall be recoverable in any court of competent jurisdiction.

The statutory basis for penalties is set out in G.S. 62-310:

> (a) Any public utility which violates any of the provisions of this Chapter or refuses to conform to or obey any rule, order or regulation of the Commission shall, in addition to the other penalties prescribed in this Chapter forfeit and pay a sum up to one thousand dollars ($1,000) for each offense, to be recovered in an action to be instituted by the Superior Court of Wake County, in the name of the State of North Carolina on the relation of the Utilities Commission; and each day such public utility continues to violate any provision of this Chapter or continues to refuse to obey or perform any rule, order or regulation prescribed by the Commission shall be a separate offense.

The Commission has not construed G.S. 62-139 to mandate comprehensive refunds in all applicable cases, although it may certainly choose to require such refunds. See In Re Provision of Intrastate Telecommunications Services by Holiday Inn of Williamston Without a Certificate of Public Convenience and Necessity, Docket No. P-298, Order Denying Motion to Cease and Desist, Issued October 27, 1992. The Commission, however, went on to note in that case:

> Even so, the Commission has frequently required comprehensive refunds. This has been a common practice in the case of interexchange carriers (IXCs) who have provided service prior to certification. The rationale here is that IXCs are companies specializing in telecommunications and either know, or should know, regulatory requirements and that such refunds are a substantial deterrent to illicit operations. (Id., p. 6)

The Commission has been generally consistent in requiring comprehensive, individualized refunds from IXCs which provided service prior to certification. Refund amounts have varied from as little as a few thousand dollars to over four hundred thousand dollars in one case.

The case containing the most complete articulation of the policy of comprehensive refunds was In Re Application of Corporate Telemanagement Group, Inc., Docket No. P-252, Issued August 13, 1991. It was also the case involving the highest level of refunds--over $400,000. No exceptions were filed with the full Commission; and the Commission recently reaffirmed the original Order's refund provisions. See In Re Application of Corporate Telemanagement Group, Docket No. P-252, Order Deny Motion For Reconsideration Except as to Uncollectibles, Issued March 10, 1993.

The policy of comprehensive, individualized refunds has certain merits. It is supportable as a matter of law. Since, technically, the IXC ought not to have been charging to begin with, the amount to be paid back is rationally related to the "harm"--it is the amount collected. It should be, at least in a theoretical sense, easy to calculate.

Theory has not always worked out in practice, however. The policy of comprehensive, individualized refunds has proved cumbersome in many instances. Assembling records can be a long, expensive, and tedious process for the companies. Renewed objections have been raised that the amount to be refunded is often disproportionate to the harm, and that the harm to the customers is tangential or nonexistent. A better view is that a more appropriate remedy to the harm to the regulatory process is not a policy of refunds but one of penalties.

While continuing to believe that the comprehensive refund policy is well-supported as a matter of law, the Commission believes that it should <u>prospectively</u> switch to penalties under G.S. 62-310 for IXC applications as a matter of policy.

There are three factors which should be taken into consideration when framing a policy of penalties (not necessarily in the order of priority).

1. The penalty should be equitable and should have a rational basis.

2. The penalty should be sufficient to act as a deterrent to misconduct.

3. The formulation and implementation of the penalty should be relatively easy to administer, not only as to the Public Staff and Commission but also as to the companies.

The penalty policy adopted by this Order for IXCs operating illegally in North Carolina will incorporate the following elements as guidelines:

1. There will be a penalty of $3,000 for the first month of illicit operation and $2,000 for each additional month or portion thereof.

2. Such penalty may be increased by an additional amount up to $10,000 by a showing of aggravating circumstances. Since the guidelines herein fall well below the statutory maximum under G.S. 62-310, it is not appropriate to consider mitigating circumstances.

3. The Commission will continue to insist that IXCs operating without a certificate cease and desist from soliciting or providing service for compensation. The IXC has the option of either ceasing to charge and continuing to operate or of ceasing to operate altogether in North Carolina.

4. Failure to complete payment of the penalty by the IXC as required will be grounds for revocation of the IXC's certificate.

5. The above policy will be applied prospectively to IXCs which have not yet received their final certificates.

The Commission believes that the level of penalty is appropriate in striking a balance between the overly indulgent and the overly punitive. As such, it is equitable and has a rational basis since the total amount of the penalty is related to the length of time in violation. It should be relatively easy to administer because the penalty eliminates much of the subjectivity and guesswork about the sanction which would otherwise be the case if other factors were figured in. The IXC, Public Staff, and Commission will know ahead of time the amount of penalty the IXC is facing. The IXC will no longer have to perform an exhaustive search of its records to comply with a refund mandate.

The Commission also believes that the other guidelines are appropriate. The aggravating circumstances provision addresses the situation, among others, in which the IXC engages in wrongful or contumacious conduct. It is also appropriate that the Commission should continue to insist that uncertified IXCs cease and desist from charging for their services, if they wish to continue to operate, or cease operation altogether as a necessary consequence of G.S. 62-110(a) and G.S. 62-3(23)a.6. This is an established practice by the Commission and encourages IXCs to complete their certification applications expeditiously. The revocation of certification upon failure to pay the penalty is necessary to ensure that the penalty is indeed paid. Indeed, the Commission believes that, as a general rule, IXCs should discharge penalties before certification becomes final.

Lastly, the Commission believes that these guidelines should apply only to illicit IXCs and should be prospective in nature. Prospectivity is appropriate in order to avoid prolonged and complicated reopening of already decided cases which were rightly decided according to the principles then applicable. Prospectivity is a commonly used administrative device and is highly appropriate here. The limitation of these guidelines to illicit IXCs is appropriate because these guidelines were drawn up with this particular subject matter in mind and because the prosecution and processing of IXC applications engages a significant amount of the Commission's and Public Staff's resources.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby promulgates the guidelines as set out in the conclusions above for application in dockets involving IXCs which have solicited or provided intrastate service in North Carolina prior to certification.

2. That the guidelines set out in the conclusions above apply prospectively to IXCs which have not yet received final certification as of the date of issuance of this Order. An IXC which has had a hearing on its application prior to the issuance of this Order but which has not been granted final certification prior to the issuance of this Order may petition the Commission to revise any refund provision to a penalties provision.

3. That copies of this Order be sent to all parties to this docket, including all IXCs and all IXCs with certificate applications pending.

4. That the Chief Clerk include a copy of this Order in the Reseller's Packet.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of April 1993.

NORTH CAROLINA UTILITIES COMMISSION
Gail Lambert Mount, Deputy Clerk

(SEAL)

Commissioner Laurence A. Cobb dissents.

DOCKET NO. P-100, SUB 72

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation to Consider Whether Competitive Intrastate Offerings of Long-Distance Telephone Service Should be Allowed in North Carolina and What Rules and Regulations Should be Applicable to Such Competition if Authorized	ORDER MODIFYING CEILING RATE PLAN AND FINANCIAL REPORTING REQUIREMENTS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on September 14, 1993, at 9:30 a.m.

BEFORE: Chairman John E. Thomas, Presiding, and Commissioners William W. Redman, Jr., Charles H. Hughes, Laurence A. Cobb, Allyson K. Duncan, Ralph A. Hunt and Judy Hunt

APPEARANCES:

For AT&T Communications of the Southern States, Inc.:

Gene V. Coker, AT&T Communications of the Southern States, Inc., 1200 Peachtree Street, N.E., Atlanta, Georgia, 30309

William A. Davis, II, Tharrington, Smith & Hargrove, Post Office Box 1511, Raleigh, North Carolina, 27602

For GTE South Incorporated and Contel of North Carolina, Inc., d/b/a GTE North Carolina:

Robert W. Kaylor, Bode, Call & Green, Attorneys at Law, P.O. Box 6338, Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28680-1269

For the Public Staff:

Robert B. Cauthen, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the Attorney General:

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

BY THE COMMISSION: This docket was opened with the filing on November 6, 1992, of a petition by AT&T Communications of the Southern States, Inc. (AT&T) requesting that the Ceiling Rate Plan (CRP) be modified by eliminating rate of return regulation from the plan and by removing the caps on AT&T's voice-grade private line (VGPL) services. By Order of November 16, 1992, the Commission requested comments. Initial comments were filed by the Public Staff, GTE South Incorporated and Contel of North Carolina d/b/a GTE North Carolina (GTE), and Carolina Utility Customers Association, Inc. (CUCA). Reply comments were filed by AT&T, the Attorney General, and CUCA. By Order dated May 5, 1993, the Commission set a hearing on September 14, 1993, on the elimination of rate of return regulation and denied AT&T's request to remove the caps on AT&T's VGPL services.

On July 2, 1993, AT&T prefiled the testimony of Kathleen Ann Cummings, David L. Kaserman, and James Mertz. On August 13, 1993, the Public Staff filed the affidavits of J. Todd Clapp, Supervisor of the Communication Section, Accounting Division, and Hugh L. Gerringer, Engineer in Charge, Toll Rate Section, Communications Division, and a Notice of Affidavits. On September 7, 1993, CUCA filed a request to cross-examine the Public Staff witnesses.

The hearing was held as scheduled. AT&T offered the testimony of Ms. Cummings, Mr. Kaserman, and Mr. Mertz. The Public Staff offered the testimony of Mr. Clapp and Mr. Gerringer.

On the basis of the testimony and exhibits received at hearing, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. The CRP was established by an Order in this docket dated February 22, 1985. Since that time the CRP has been modified by Orders in 1986, 1987 and 1990.

2. As a result of the modifications to the CRP, the only services offered by AT&T which are subject to any limitation on rate increases are message toll service (MTS) and voice grade private line (VGPL) services. Rates on those services may be increased so long as they do not exceed a cap.

3. The theoretical applicability of rate of return regulation is one of the few remaining differences in the regulation of AT&T as compared to other interexchange carriers.

4. Elimination of rate of return regulation will not harm the public and will benefit AT&T.

5. Elimination of rate of return regulation makes the prescription of depreciation rates, financial reporting requirements, and compliance with the Uniform System of Accounts unnecessary.

6. Treatment of special service arrangements, new services, and changes in rates as informational filings allowed to become effective on 14 days' notice would establish a consistent standard applicable to all interexchange carriers (IXCs).

7. Treatment of special promotions as informational filings allowed to become effective on three days' notice would allow sufficient time for review, and yet permit the promotional filings to go in effect on a timely basis. In the event AT&T can show a need for such tariffs to become effective on a shorter notice, it can request a waiver of the three-day notice period in its filing.

EVIDENCE AND CONCLUSIONS

The testimony of all of the witnesses in this proceeding supports at least one simple conclusion: whatever the theoretical value or applicability of rate of return regulation and the attendant financial reporting requirements, the elimination of such regulation and reporting requirements will have no adverse effect on the public or the regulatory process and will be beneficial to AT&T. This is true whatever the degree of competition is in the interexchange market and whether or not AT&T remains a price leader in that market. In addition to noting the practical benefit arising from elimination of rate of return regulation, the Commission notes that the objective of uniform treatment of all IXCs will also be advanced.

The Commission concludes that AT&T's petition for elimination of rate base/rate of return regulation, the associated prescribed depreciation rates and financial reporting requirements and the use of the Uniform System of Accounts should be granted. The Commission further concludes that financial reporting requirements should be eliminated for all IXCs to promote more nearly equal regulatory treatment. However, the Commission specifically reminds AT&T and all IXCs that the payment and reporting requirements relating to the Regulatory Fee and its administration as required under G.S. 62-302 and NCUC Rule R15-1, Regulatory Fee, remain applicable and unchanged.

The Commission concludes that the recommendation of the Public Staff that special service arrangements, new services and changes in rates be treated as informational filings allowed to become effective on 14 days' notice would establish a consistent, reasonable and equitable standard applicable to all interexchange carriers.

The Commission concludes that special promotions should be treated as informational filings allowed to become effective on three days' notice. A three-day notice period will allow sufficient time for review and yet will permit the promotional filing to go in effect on a timely basis. In the event AT&T can show a need for such tariffs to become effective on a shorter notice, it can request a waiver of the three-day notice period in its filing.

IT IS, THEREFORE, ORDERED as follows:

1. That rate base/rate of return regulation, its associated prescription of depreciation rates, and the use of the Uniform System of Accounts be eliminated for AT&T.

2. That financial reporting requirements be eliminated for all IXCs. (Except for those that relate directly to the payment and reconciliation of the regulatory fees as provided for in G.S. 62-302 and administered under NCUC Rule R15-1.)

3. That the Ceiling Rate Plan be modified as shown in the attached Appendix A to incorporate the Commission's conclusions set out above.

4. That all IXCs shall file revisions to the special service arrangement section and the special promotion section of their tariffs in order to bring those tariff sections into conformance with the decisions reached herein.

5. That the Commission reserves the right to reimpose financial reporting requirements in the future should such reporting requirements be deemed necessary to the regulatory process.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of December 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

Initial Establishment of Rates, Charges, and Regulations

All new carriers seeking authority to provide long-distance service shall file tariffs with the application for a certificate reflecting the proposed immediate service area, regulations, rates, and charges.

Changes in Rates - Facilities-Based Carriers and Resellers

To increase rates the facilities-based carriers and resellers other than AT&T Communications of the Southern States, Inc. (AT&T), must file tariffs and a proposed subscriber notice or notices with the Public Staff at least 14 days prior to the effective date of the change. In addition, the proposed notice to customers must be sent to the affected subscribers at least 14 days prior to the effective date of the change. If the proposed notice is found to be inadequate, the implementation date of the rate change will be suspended until such time as customers are adequately notified. This requirement is also applicable for any rate restructure which would result in a combination of increases or decreases to the carrier's subscribers. All decreases in rates may become effective after filing appropriate tariffs with the Public Staff at least 14 days prior to the proposed effective date.

Changes in Rates - AT&T

Proposed increases in rates above AT&T's current capped rates for message telephone service (MTS) and voice-grade private lines will be handled as follows: AT&T should file proposed tariffs along with a written explanation, support of its filing, and a proposed customer notice for review by the Commission and the Public Staff. The Commission will conduct such proceedings as it deems appropriate in light of the nature of the filing. No increase in rates above applicable caps shall go into effect without Commission approval.

To increase rates for all services other than MTS and voice-grade private lines and to increase rates up to its current capped rates for MTS and voice-grade private lines, AT&T must file a tariff and proposed subscriber notice with the Public Staff at least 14 days prior to the proposed effective date of the change. In addition, the proposed customer notice must be sent to all affected subscribers at least 14 days prior to the effective date of the change. If any proposed notice to customers is found to be inadequate, the implementation date of the rate change will be suspended until such time as customers are adequately notified. This requirement is also applicable for any rate restructure which would result in a combination of rate increases and decreases to AT&T's subscribers not exceeding the Company's capped rates for MTS and voice-grade private lines.

Decreases in rates for all services offered by AT&T may become effective after filing appropriate tariffs with the Public Staff at least 14 days prior to the proposed effective date.

Notwithstanding the above provisions, AT&T shall not at any time increase operator/calling card usage rates above the rate in effect for AT&T's MTS 1+ direct dialed calls without Commission approval.

Discontinuance of Service - All Carriers and Resellers

To discontinue service, the carrier must file appropriate tariffs and a proposed subscriber notice with the Public Staff at least 60 days prior to the proposed effective date of the change. In addition, the proposed subscriber notice must be sent to the affected subscribers at least 60 days prior to the proposed effective date.

Additions of New Services - All Carriers and Resellers

To add a new service to the carrier's offerings, the carrier must file appropriate tariffs with the Public Staff at least 14 days prior to the effective date of the change. No cost support for new services need be filed. Tariffs for new services will become effective after the minimum notice period unless the carrier consents to a suspension and will be treated as presumptively valid; i.e., any objection or challenge to the tariff will be handled as a complaint proceeding pursuant to G.S. 62-75.

Additions to Service Area

Carriers will be allowed to add new originating service areas on one day's notice to the Commission and the Public Staff by an appropriate tariff filing.

Offerings of Special Promotions - All Carriers and Resellers

To offer a special promotion, the carrier must file appropriate letters and/or tariffs with the Public Staff at least three days prior to the effective date of the offering. Promotions will be treated as presumptively valid and will become effective after the minimum notice period unless the carrier consents to a suspension. Any objection or challenge to the promotion will be handled as a complaint proceeding pursuant to G.S. 62-75.

DOCKET NO. P-100, SUB 84

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Issuance of Special Certificates for Provision of Telephone Service by Means of Customer-Owned Pay Telephones	)))	ORDER AMENDING COCOT RULES TO AUTHORIZE INTERNATIONAL CALL BLOCKING

BY THE COMMISSION: On October 12, 1992, Southern Bell Telephone and Telegraph Company (Southern Bell) filed a motion to amend Rule R13-5(h). Rule R13-5(h) currently reads as follows:

(h) All PTAS instruments must be capable of completing local or long distance calls.

Southern Bell stated that it has filed with the Commission a tariff to provide international call blocking to Southern Bell's Public Telephone Access Service (PTAS) subscribers. Southern Bell stated that this tariff was needed because the "incidence of fraudulent international calling over their facilities is high." Such blocking is currently not allowed by Rule R13-5(h) because of the requirement that all PTAS instruments be capable of completing local and long distance calls.

Southern Bell proposed the following rewrite of Rule R13-5(h):

(h) All PTAS instruments must be capable of completing local and long distance calls, however, sent-paid international calling capability may be blocked where the incidence of fraud is high.

It should also be noted that the Federal Communications Commission (FCC) addressed the issue of international calling fraud in CC Docket No. 91-35 entitled Policies and Rules Concerning Operator Service Access and Pay Telephone Compensation. (FCC Order). The FCC Order stated:

. . .[W]e direct local exchange carriers to offer in locations where technically feasible, within six months, tariffed services that will block direct-dialed international calls. (FCC Order at 7).

The FCC further added:

> [W]e direct local exchange carriers to offer in locations where technically feasible within six months, tariffed originating line and billed number screening services that indicate to operator service providers any billing restrictions on lines to which a caller may seek to bill a call. (Id).

The FCC Order was released on July 10, 1992.

On November 10, 1992, the Commission issued an Order Initiating Rulemaking Regarding Rule R13-5(h).

<u>Initial Comments:</u>

The following parties filed comments: The Public Staff; GTE South (GTE); Central Telephone Company (Central); International Quarter Phones, Inc.; Huffman Oil Company; Eastern Distributing Company, Inc.; Carolina Telephone and Telegraph Company (Carolina); the North Carolina Payphone Association (NCPA); Southern Bell; and AT&T Communications of the Southern States, Inc. (AT&T).

Southern Bell, along with the NCPA, offered the most comprehensive comments in favor of the blocking proposal. Southern Bell stated that there were approximately 3,199 COCOT providers operating in its territory generating significant annual revenues to Southern Bell. Southern Bell noted that the COCOT industry was experiencing "a tremendous amount of fraud as a result of international calling." Much of this fraud occurs when an end-user "clips on" or attaches to the access line a device with dialing capabilities. The end-user can dial a number anywhere without incurring a charge. Southern Bell noted that the FCC Order noted above had acknowledged the problem of international fraud and directed LECs to offer, where feasible, tariffed service that will block direct-dialed international calls. Bell South filed such a tariff at the FCC on November 28, 1992, to be effective on January 8, 1993. Southern Bell stated that it offered international call blocking in all the other states where it operates and that this has greatly reduced the incidence of fraud.

The NCPA echoed Southern Bell's comments and cited specific incidences of significant toll fraud. The NCPA requested that the Commission require all LECs to make international direct-dial blocking available promptly and on a separate unbundled basis at cost-based, rather than "premium" rates. The NCPA also requested that LECs be required to offer "originating-line screening" and "billed number screening" in accordance with the FCC Order.[1]

Carolina was in basic agreement with Southern Bell's proposal but argued that the phrase "where the incidence of fraud is high" was too subjective. Carolina proposed the following:

---

[1]Originating line screening allows the determination that the call is being placed, for example, at a payphone location. Billed number screening permits automatic prevention of third-number or collect billing on the line.

(h) All PTAS instruments must be capable of completing local or long distance calls, however, sent-paid international calling capability may be blocked upon request by the PTAS vendor.

GTE concurred in the Southern Bell motion and noted the existence of the FCC Order.

The Public Staff withheld comments at the preliminary stage but stated that, if international blocking is made available by the LECs, it should be available as a self-supporting option, separate from existing blocking options, so that COCOT providers are not required to obtain sent-paid international blocking in order to obtain other blocking features.

Central concurred in the Southern Bell motion and with the Public Staff's suggestion regarding the terms for availability of international blocking.

AT&T supported the rule change proposed by Southern Bell with the clarification that sent-paid international blocking is to include both 011+ and 10XXX-011+ calls and in addition require all LECs to make international call blocking available. AT&T also proposed that the Commission should initiate a proceeding to make available international sent-paid blocking, as well as domestic originating line and billed number screening services, to all aggregators in North Carolina.

Reply Comments:

The following parties filed reply comments: The Public Staff and the Attorney General.

Concurring generally with Carolina concerning the proposed revision of Rule R13-5(h), the Public Staff offered the following language:

(h) All PTAS instruments must be capable of completing local and long distance calls; sent-paid international calls may be blocked.

The Public Staff also concurred with AT&T's suggestion that any international blocking service offered by the LECs should cover both 10XXX-011+ and 011+ calls and that the tariffs should clearly specify that both types will be blocked.

The Attorney General favored the language proposed by Southern Bell since it seems to embody some showing of fraud.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission believes that there is adequate support to modify Rule R13-5(h) to authorize international call blocking. The Commission also believes a variation of Carolina's proposed wording would accomplish this goal and would be easy to administer:

(h) All PTAS instruments must be capable of completing local and long distance calls; provided, however, that sent-paid international calling capability may be blocked.

The Commission further believes that it is generally preferable to confine the duties of the LECs with respect to PTAS providers to the LEC tariffs. Accordingly, all LECs should be instructed to file tariffs that would allow for the blocking of sent-paid international calling capability for PTAS locations by certification by the PTAS provider that the incidence of fraud in such calling is high.

In view of the general rule against blocking from public payphones, the Commission is of the opinion that end-users should receive notice that international call blocking is in force, even though this point was not addressed by the commenting parties. Although this may cause PTAS providers to incur some extra expense, the Commission believes that this expense is justified by the public interest in straightforward end-user notice. Accordingly, the Commission is of the opinion that Rule R13-4(a) (Required Notice) should be amended to add a subsection (7) to read:

> (a) The following information must be posted at each PTAS instrument other than those located in the detention areas of local, state, or federal confinement facilities:
>
> > . . .(7) Whether international calling capability is blocked from the PTAS instrument.

Because confinement facility phones are already extensively blocked, it does not seem necessary to modify the notice requirements regarding confinement facility payphones set out in Rule R13-4(b).

With respect to mandating that LECs offer "originating-line screening" and "billed number screening," the Commission does not believe that it is necessary that the Commission act on these matters. The FCC has already issued an Order in CC Docket No. 91-35 mandating that the LECs offer such blocking as of January 1993 where technically feasible. In view of this FCC action, it is the opinion of the Commission that there has been no showing that additional action by the Commission is necessary.

Similarly, AT&T's request for further hearings to include matters related to 10-XXX unblocking by aggregators falls outside the scope of this docket and should not be considered herein.

IT IS, THEREFORE, ORDERED as follows:

1. That Rule R13-5(h) be amended to read as follows:

> "(h) All PTAS instruments must be capable of completing local and long distance calls; provided, however, that sent-paid international calling capability may be blocked."

2. That Rule R13-4(a) be amended by adding a new subsection (7) to read:

> "(7) Whether international calling capability is blocked from the PTAS instrument."

3. That all LECs regulated by this Commission be required to file tariffs by no later than 30 days from the issuance of this Order allowing for the

blocking of sent-paid international calling capability for PTAS locations upon certification by the PTAS provider that the incidence of fraud in such calling is high.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of January 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. P-100, SUB 84

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Issuance of Special Certificate for Provision of Telephone Service by means of Customer-Owned Pay Telephones	ORDER AMENDING RULE R13 AS TO LINE CONCENTRATORS AND CUT-OFF SWITCHES

BY THE COMMISSION: On April 12, 1993, the Commission issued an Order Allowing Line Concentration in Confinement Facilities and Seeking Proposed Rule Changes. "Line concentration" refers to a means of combining payphone sets serving multiple locations on one line using a call processor. The Commission found that the utilization of line concentration and cut-off keys was in the public interest in confinement facilities and should be allowed in those contexts. The Commission also found that the appropriate charges for line concentrated payphones were the STS trunk and usage rates. Recognizing the need for conforming changes in the rules, the Commission solicited comments from interested parties.

The Public Staff, the Attorney General, and the North Carolina Payphone Association (NCPA) replied.

The Public Staff suggested that the definitions of "cut-off switch or key", "line concentrator", "PTAS line" and "PTAS trunk" should be added to the Rule by adding to/revising R13-1 as follows:

Rule R13-1. Definitions.

(a) Provider, COCOT Provider, or PTAS Subscriber. The subscriber to a Public Telephone Access Service (PTAS) line or PTAS trunk who offers telephone service to the public by means of a coin, coinless, or key-operated PTAS instrument.

(g) Cut-off Switch or Key. An item of terminal equipment which enables a PTAS instrument to be easily connected or disconnected from the exchange network. A cut-off switch or key does not have the capability of switching a given PTAS instrument from one PTAS line or PTAS trunk to another. Cut-off switches or keys may be used only in confinement facilities and only at the request of the administration of the confinement facility.

(h) Line Concentrator. An item of registered terminal equipment which enables two or more PTAS instruments to obtain access, through manual or automatic switching, to the same PTAS trunk but denies connection to the same trunk at the same time. Such equipment may be used only in confinement facilities and only with the express written consent of the administration of the confinement facility.

(i) PTAS Line. The exchange access facility furnished by the local exchange company which is used to connect PTAS instruments to the network when a line concentrator is not utilized.

(j) PTAS Trunk. The exchange access facility furnished by the local telephone company which is required in lieu of a PTAS line when the provider utilizes a line concentrator between the PTAS instrument and the exchange network as allowed by Rule R13-6.

The Public Staff suggested that the definitions in Rule R13-1 should be arranged alphabetically before finalization.

To recognize an alternate means of connecting PTAS instruments to the network, Rule R13-2 should be modified as follows:

Rule R13-2. PTAS Line or Trunk.

(a) All PTAS instruments and all voiceless facsimile devices operated for compensation, other than those located in detention areas of local, state or federal confinement facilities and connected through line concentrators as specified in Rule R13-6 following, must be connected to the telephone network through PTAS lines furnished by the local exchange telephone company. Except as specified in Rule R13-6, connection through other facilities or systems is prohibited.

(b) All PTAS instruments and all voiceless facsimile devices connected to the network through line concentrators as specified in Rule R13-6 require the use of PTAS trunks furnished by the local exchange telephone company for connection of the line concentrator to the network.

(c) The PTAS subscriber is responsible for abiding by all applicable telephone company tariffs. Failure to do so is grounds for immediate disconnection of service.

To incorporate the conclusions stated in the Commission's April 12 Order, the following new paragraphs should be added to Rule R13-6:

Rule R13-6 Special Rules for Service Within Confinement Facilities.

(e) Shall, at the request of the administration of the confinement facility, provide for the cut off of designated PTAS instruments through the use of cut-off keys or switches placed on the provider side of the network interface;

(f) May, with the express written consent of the administration of the confinement facility, terminate PTAS trunks provided by the serving local exchange company for use at the facility in manual or automatic line concentrators; the concentrator may not be arranged or programmed to allow access by more than one PTAS instrument to a single PTAS trunk at any time; prior to connection of the equipment, the provider is obligated to advise the serving local exchange company of its intent to connect a concentrator to the local exchange company's facilities, specifically identify the trunks which will terminate in the concentrator and, upon demand, provide the FCC registration number of the equipment.

Certain requirements which are now contained in Commission Rule R13-5 and which are now applicable to PTAS instruments should be extended to cut-off switches and keys and concentrators by revising Rule R13-5 as follows:

Rule R13-5. General Requirements - Service and Equipment.

(a) The provider is responsible for the installation, maintenance, and operation of PTAS instruments and other terminal equipment.

(f) All PTAS instruments and all other terminal equipment must be connected to the telephone network in compliance with Part 68 of the FCC Rules and Regulations as well as the regulatory and certification requirements of the North Carolina Utilities Commission. Subscribers to Public Telephone Access Service (PTAS) may, upon request, be required to provide the telephone company with the FCC registration number of each item of terminal equipment to be connected prior to its connection.

(g) All PTAS instruments and all other terminal equipment must be installed in compliance with the current National Electrical Code and National Electrical Safety Code.

Attorney General's Comments and Proposals.

The Attorney General suggested that Rule R13-6 be amended to add the following subsection (f):

> Notwithstanding any other rules in this Chapter, PTAS instruments located in the detention areas of local, state or federal confinement facilities:
>
> . . .
>
> (f) May, if specifically requested by the administration of the confinement facility, be combined on one telephone access line using a single call processor or may be controlled by cut-off keys and switches; provided that if multiple PTAS instruments are combined on one telephone line using a single call processor, the telephone line shall be tariffed at STS trunk and usage rates.

NCPA Comments. The NCPA stated that it favored the adoption of the Public Staff's proposed rules as more comprehensively reflecting and implementing the Commission's Order of April 12, 1993.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration of the filings in this docket, the Commission is of the opinion that the amendments suggested by the Public Staff to Rule R13 for the purpose of conforming these rules to the Commission's April 12, 1993, Order allowing line concentration and cut-off switches or keys in confinement facilities should be promulgated. The Commission notes that there were no substantial objections to these rules and that, in fact, the NCPA favored their adoption.

As suggested by the Public Staff, the definitions in Rule R13-1 have been alphabetized.

IT IS, THEREFORE, ORDERED as follows:

1. That the amendments to Rule R13 as set out in Appendix A be promulgated.

2. That a copy of this Order be sent to all persons to whom the February 4, 1993, Order seeking comments concerning line concentration in confinement facilities was sent, including all COCOT special certificate holders.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Errata Order (6-9-93)
Errata Order (11-8-93)

APPENDIX A

A. Rule R13-1 Definitions. is rewritten to read as follows:

"(a) Automated Collect Call. A call placed and billed to the called telephone number without the assistance or intervention of a human operator.

(b) Cut-Off Switch or Key . An item of terminal equipment which enables a Public Telephone Access Service (PTAS) instrument to be easily connected or disconnected from the exchange network. A cut-off switch or key does not have the capability of switching a given PTAS instrument from one PTAS line or PTAS trunk to another. Cut-off switches or keys may be used only in confinement facilities and only at the request of the administration of the confinement facility.

(c) End User. The person initiating a call from a pay telephone instrument.

(d) Facsimile. The device or process by which information on documents is converted to an electronic format, conveyed over the telephone network, and reconverted into documentary form. A facsimile device which does not incorporate a telephone is a 'voiceless-facsimile device.'

(e) Line Concentrator. An item of registered terminal equipment which enables two or more PTAS instruments to obtain access, through manual or automatic switching, to the same PTAS trunk but denies connection to the same trunk at the same time. Such equipment may be used only in confinement facilities and only with the express written consent of the administration of the confinement facility.

(f) Provider, COCOT Provider, or PTAS Subscriber. The subscriber to a PTAS line or PTAS trunk who offers telephone service to the public by means of a coin, coinless, or key-operated PTAS instrument.

(g) PTAS Instrument. A coin, coinless, or key-operated telephone or facsimile device, other than a voiceless-facsimile device, capable of originating and receiving voice telephone calls.

(h) PTAS Line. The exchange access facility furnished by the local exchange company which is used to connect PTAS instruments to the network when a line concentrator is not utilized.

(i) PTAS Trunk. The exchange access facility furnished by the local telephone company which is required in lieu of a PTAS line when the provider utilizes a line concentrator between the PTAS instrument and the exchange network as allowed by Rule R13-6.

(j) Sent-Paid Call. A call paid for at the time and place of origination with cash or commercial credit card."

B. Rule R13-2. PTAS Line. is rewritten to read as follows:

"Rule R13-2. PTAS Line or Trunk.

(a) All PTAS instruments and all voiceless facsimile devices operated for compensation, other than those located in detention areas of local, state or federal confinement facilities and connected through line concentrators as specified in Rule R13-6 following, must be connected to the telephone network through PTAS lines furnished by the local exchange telephone company. Except as specified in Rule R13-6, connection through other facilities or systems is prohibited.

(b) All PTAS instruments and all voiceless facsimile devices connected to the network through line concentrators as specified in Rule R13-6 require the use of PTAS trunks furnished by the local exchange telephone company for connection of the line concentrator to the network.

(c) The PTAS subscriber is responsible for abiding by all applicable telephone company tariffs. Failure to do so is grounds for immediate disconnection of service."

C. Rule R13-6. <u>Special rules for service within confinement facilities.</u> is amended to add new subsections (f) and (g) to read:

"(f) Shall, at the request of the administration of the confinement facility, provide for the cut off of designated PTAS instruments through the use of cut-off keys or switches placed on the provider side of the network interface;

(g) May, with the express written consent of the administration of the confinement facility, terminate PTAS trunks provided by the serving local exchange company for use at the facility in manual or automatic line concentrators; the concentrator may not be arranged or programmed to allow access by more than one PTAS instrument to a single PTAS trunk at any time; prior to connection of the equipment, the provider is obligated to advise the serving local exchange company of its intent to connect a concentrator to the local exchange company's facilities, specifically identify the trunks which will terminate in the concentrator and, upon demand, provide the FCC registration number of the equipment."

D. Rule R13-5. <u>General Requirements--Service and Equipment.</u> is amended by rewriting subsections (a), (f), and (g) to read:

"(a) The provider is responsible for the installation, maintenance, and operation of PTAS instruments and other terminal equipment.

(f) All PTAS instruments and all other terminal equipment must be connected to the telephone network in compliance with Part 68 of the FCC Rules and Regulations as well as the regulatory and certification requirements of the North Carolina Utilities Commission. Subscribers to PTAS may, upon request, be required to provide the telephone company with the FCC registration number of each item of terminal equipment to be connected prior to its connection.

(g) All PTAS instruments and all other terminal equipment must be installed in compliance with the current National Electrical Code and National Electrical Safety Code."

DOCKET NO. P-100, SUB 89

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of the Manner in Which Extended Area Service is Implemented in North Carolina	)))	ORDER FURTHER AMENDING RULE R9-7 AND REQUESTING COMMENTS ON ADDITIONAL ISSUES

BY THE COMMISSION: On June 8, 1992, the Public Staff filed a Motion for Further Consideration and Modification of Order. The Public Staff argued that the community of interest factor (CIF) and percentage making calls (PMC) standards should be eliminated and instead the Commission should rely on the level of demonstrated support as the threshold test and subscriber pollings as the final basis for EAS approval.

In support of its motion, the Public Staff pointed out the following alleged problems with the Order of May 5, 1992, and the attendant rules:

1. Definitions and methodology regarding CIFs and PMCs.

   a. How CIFs are to be derived--e.g., how MTS, FX, WATS, private lines, local calling plans, access lines, accounts are to be considered.

   b. Whether CIFs and PMCs are accurate considering they come from the local exchange companies (LECs).

   c. Difficulty of obtaining meaningful and complete traffic information for interLATA routes, since some interexchange carriers (IXCs) do not track the data.

   d. Definition for "persons making calls" in connection with the PMC.

   e. No provision of dispensing with the calling study requirement where there is no rate increase.

   f. Use of toll-calling studies when non-regulated exchanges of telephone membership corporations (TMCs) are involved.

2. CIFs and PMCs are not reliable indicators on which to base community of interest findings or polling decisions. Specifically, the Public Staff argued that the CIFs and PMCs do not reflect pent-up demand or the presence of occasional callers, nor are certain types of calls--e.g., intraLATA reseller traffic, special access traffic, private lines, etc.--considered. The Public Staff listed a number of EAS proposals that went to polling and were approved despite there being routes in the proposal on which the CIFs and PMCs that did not meet the current standards.

3. The procedure under the rule amendments is neither certain nor objective but arbitrary. Specifically, there is no definition or set of criteria defining "special circumstances," which allow the CIF and PMC standards to be suspended.

On June 24, 1992, the Commission requested comments from interested parties.

The following parties responded with comments: Central Telephone Company (Central), AT&T Communications of the Southern States, Inc. (AT&T), Carolina Telephone & Telegraph Company (Carolina), GTE, and Southern Bell Telephone and Telegraph Company (Southern Bell).

Central stated that while it agreed with the Public Staff that some of the aspects of the EAS rule amendments regarding CIFs and PMCs are unclear, Central does not agree with eliminating them as a basis for evaluating EAS requests. But, whereas clarifying the definitions of CIFs and PMCs would be relatively easy, the same could not be said for "demonstrated support," the Public Staff's primary criterion. Central suggested that the Commission clarify the call-types to be used in point-to-point calling studies as a means to produce standard statistical data among the different companies.

AT&T stated that the promulgated rule was "clear and unambiguous" as written and, therefore, needs no clarification.

Carolina noted that the Public Staff had never before questioned the accuracy of LEC-provided CIF data. While CIFs and PMCs are not perfect, Carolina called them the "best measurement tool available." Since EAS shifts the economic burden to small business and residential customers, it is appropriate to exclude FX, WATS, and private line usage from calculation of the CIF. Carolina also stated that the fact that EAS matrix application would not result in rate increases should not mean that calling studies should be dispensed with. Carolina further argued that, as to "special circumstances," it would be impractical, if not impossible, to list all the special circumstances that may exist.

GTE opposed the Public Staff's motion on more general grounds. GTE stated that the industry was meeting to arrive at satisfactory regional calling plans.

Southern Bell filed a more detailed response in opposition to the Public Staff's motion. With respect to the accuracy of CIFs and PMCs, Southern Bell stated that these calculations have been used for many years and the Public Staff never questioned their accuracy. While interLATA data may be hard to obtain, this rarely creates a problem in EAS proposals since few EAS proposals involve interLATA routes. Southern Bell agreed with Carolina that, even in the absence of rate additives, calling studies should be made with a view to determining whether EAS is appropriate. Southern Bell argued strenuously that the new rules combined objectivity with flexibility. The new rules are not a straitjacket. As to the examples cited by the Public Staff where subscribers had voted favorably but the proposals would not have met the new calling study standards, Southern Bell questioned the reliability of polls, given the relatively small subscriber response to them. Southern Bell suggested that, if anything, there was a correlation between PMCs and percent total customers supporting EAS. Lastly, Southern Bell argued that the new rules provide at least as much certainty to EAS applications--indeed more--as was provided by the former rule.

On September 22, 1992, the Commission issued an Order requesting (1) a list of all types of calls included in calling data used to determine CIFs and the rationale for including or excluding types of calls and (2) an explanation of how PMCs are calculated.

The following LECs filed comments as summarized below:

Concord Telephone Company (Concord)

1. Concord has not used a standard CIF in the past. When a CIF has been computed only MTS usage was developed, since other usage data is hard to obtain and the accuracy is questionable.

2. PMC has been developed by taking the number of accounts billed and dividing it by the number of accounts with toll in proposed EAS arrangement.

Pineville Telephone Company (Pineville)

Pineville has never been required to make such studies.

1. Pineville would propose to use MTS, FX, WATS, and private line or all types of calls providing revenues that would be eliminated by EAS to determine CIF.

2. PMC would be developed by separate accounts. For example, all single line residence would be one account and all multi-line business would be one account if in a rotary group. If a multi-line residence or business had separate billing numbers for each line, they would have one account per line/number.

Mebane Home Telephone Company (Mebane)

1. Mebane includes only MTS in the calculation of CIFs. The amount of WATS and FX service is considered insignificant. Private line traffic does not generate detailed traffic information and therefore cannot be included. Mebane has no local calling plans.

2. PMCs are calculated by dividing access lines with at least one MTS call in a month by total access lines.

Ellerbe Telephone Company (Ellerbe)

Ellerbe has no formal policy but requests guidance from the Commission and the Public Staff when the need arises.

Randolph Telephone Company (Randolph)

1. Randolph has not considered EAS since the early 1960's and, therefore, would look to the Commission for guidance.

2. PMC would be calculated by determining the number of subscribers calling and dividing by total subscribers.

Lexington Telephone Company (Lexington)

1. Lexington uses only MTS. For intraLATA routes Lexington uses MTS handled by Southern Bell; for interLATA routes, MTS from AT&T, since AT&T is the only IXC Lexington does recording for. Even when requested, other IXCs do not provide the information. WATS is measured on a minutes-of-use (MOU) basis, so no recording of individual calls is available. FX and private line service are flat rated, so no recording is done. Lexington has no local calling plans.

2. Lexington does not attempt to calculate percentage of persons making calls but rather calculates percentage of access lines making calls by dividing number of access lines making calls by number of access lines in study.

North State Telephone Company (North State)

1. North State uses only MTS calls. For intraLATA routes, North State uses MTS handled by Southern Bell; for interLATA routes, MTS from AT&T, since AT&T is the only IXC for which North State does recording. All categories of access

lines are included: business individual lines, key system trunks, PBX trunks, Centrex station lines, FX (toll only), and official business; residence individual lines and FX (toll only). Traffic over private lines or dedicated facilities is excluded, because it is not recordable.

2. PMC = total access lines carrying originating traffic/total access lines in service at originating point.

Central

1. Central uses MTS or point-to-point calls, including direct-dialed and operator assisted calls, MTS calls from FX number, and optional toll calling plan calls. Central excludes WATS (not included in point-to-point studies) and coin stations and company official calls (not viewed as customer lines). CIF = number of point-to-point calls/number of accounts in exchange. Number of accounts, not number of lines, better represents number of customers in an exchange.

2. PMC = number of accounts making calls/number of total accounts.

Carolina

1. Carolina includes MTS, originating sent-paid coin, received collect, and credit card calls if billed within the originating exchange. Carolina excludes calls to 800 numbers, sent-collect, credit card calls if billed to another exchange, WATS, FX service, private line service, and local calling plan calls. Calls and services excluded are typically discounted and bulk-rated for business customers. One large customer using these services could generate sufficient volumes to exceed the Commission's standards.

2. PMC = number of customers making calls/total number of local access lines

GTE

1. GTE uses point-to-point MTS calls only, both direct-dialed and operator-assisted. This includes toll traffic on FX lines, discount calling plan calls (i.e., Saver Service) and optional toll calling plans. GTE excludes OUTWATS, INWATS, company official, private line, and local calling plan calls (i.e., TriWide). CIF = calls/access lines. Residence lines include 1-party, multi-party, key trunks, and Lifeline. Business lines include 1-party, multi-party, key lines, PBX trunks, Centrex/CentraNet NARS, public and semi-public telephones, and PTAS access lines. Company official, OUTWATS, INWATS, FX lines, and private lines are excluded.

2. PMC = customer groups making one, two, or three, etc., calls/total accounts. Each customer's main billing number is considered an account.

Southern Bell

1. Southern Bell includes calls carried by business individual lines, PBX trunks, Centrex, ESSX station lines, ISDN lines, FX (toll only), and official lines, and residence individual lines, 2-party lines, and FX (toll only). Southern Bell excludes WATS, 800, mobile, cellular, marine, air-to-ground, coin, and local intraLATA messages (any seven-digit dialed calls made in local calling

or expanded local callings areas). Coin service is excluded because coin service subscribers are typically not residents of the impacted area. Traffic over dedicated facilities is excluded because it is not recordable.

2. PMC = total access lines making calls/total access lines in service.

ALLTEL (ALLTEL Carolina, Heins, and Sandhill Telephone Companies)

1. ALLTEL uses access lines for categories of service provided under tariff in determining CIF.

2. PMC = number of accounts making at least one call/total number of accounts.

The Public Staff filed its response on November 6, 1992. The Public Staff characterized the comments of the LECs as displaying a marked lack of uniformity among the LECs in determining CIFs and PMCs. The Public Staff asserted that this further supported its position regarding the shortcomings of these statistics as valid indicators of community of interest. The Public Staff, therefore, renewed its request that the Commission amend Rule R9-7 to eliminate calling statistics as a basis for evaluating EAS requests and to rely instead on the level of demonstrated support from the affected communities as the initial test and subscriber polling as the final basis for EAS approval.

In the alternative, the Public Staff requested the Commission to further amend Rule R9 to define CIF and PMC and to specify how each should be derived. While the only definitive way the Commission and the public can be assured that calling studies are performed properly would be through an audit, at least the LECs would have some guidance and the likelihood of uniformity would be increased.

The Public Staff proposed that CIF be defined as the number of customer calls divided by the total number of customer accounts. Customer calls should include the following types when billed to an account in the originating exchange: 1+ and operator-assisted MTS calls, optional toll calling plan calls, and Saver Service calls. The Commission should require all IXCs providing intrastate service from the exchanges under study to submit information to the LEC showing the number of calls billed during the study period. Customer accounts should include those subscribing to the following types of lines/trunks: key, PBX, Centrex, ESSX, ISDN, open-end FX, simple business, and residence.

The Public Staff also proposed that PMC be defined as the number of customer accounts making more or more calls during the study period divided by the total number of customer accounts. The customer accounts used to calculate the PMC should be those subscribing to the types of lines/trunks listed above.

The Public Staff further requested that the Commission waive the use of CIFs and PMCs when non-regulated TMC routes are involved because of the difficulty of getting complete calling data from the TMCs. The use of CIFs and PMCs should also be waived when local calling plan (seven-digit dial) routes are involved, since calling data on those routes is not available. In lieu of CIFs and PMCs for both of those routes, the Commission should rely on the demonstration of broad-based support as set out in Rule R9-7(c).

On November 12, 1992, the Commission issued an Order requesting comments on the Public Staff response.

The following parties responded to the Commission's Order Requesting Comments: Carolina, Central, Concord, the Attorney General, GTE, and Triangle J Council of Governments (TJCOG).

Central and Concord agreed with the Public Staff's proposal for defining CIFs and PMCs as did the Attorney General. TJCOG supported the idea of eliminating calling studies as factors but in the alternative supported the Public Staff's proposed amendments.

Carolina, by contrast, argued that CIFs should be defined as the number of customer calls divided by the total number of local customer lines since customer lines are more readily available from industry-wide documents than customer account information. Carolina acknowledged that IXC calling data is necessary for a total analysis of calling volume, especially on interLATA routes, and it stated its willingness to incorporate these into a composite CIF calculation.

With respect to PMCs, Carolina similarly proposed that the PMC be defined as the number of access lines making calls divided by the total number of local customer lines for reasons similar to those stated above.

With respect to waivers of the use of CIFs and PMCs when nonregulated TMC routes are involved, Carolina stated its opposition. Carolina believes that the TMCs will cooperate in making this information available. With respect to routes having local calling plans, Carolina said that it did not believe that the same CIF and PMC criteria should be used as between toll routes, believing such criteria to be too low. The Commission should adopt modified (and higher) CIF and PMC criteria rather than waiving their use completely.

GTE essentially agreed with Carolina's views on the definition of CIF, stating that it had always calculated CIFs using customer lines rather than accounts. GTE argued that this was more rational since EAS surcharges are applied on a per-line rather than per-account basis. However, GTE supported the Public Staff's recommendation concerning the types of calls to be used as the numerator of the CIF ratio, as well as the proposed definition of the types of lines to be included in the denominator, provided that line quantities rather than account quantities are used.

As to the PMC definition, GTE supported the Public Staff's definition. Concerning waivers of the use of CIFs and PMCs with respect to TMCs, GTE conceded that this may be warranted when such data is unavailable, but the Commission should retain discretion to use or not to use such data dependent on the circumstances. GTE also stated that the use of CIFs and PMCs in the context of seven-digit local calling plans would reflect a high level of stimulation and be essentially meaningless.

Southern Bell, along with the other LECs, disagreed with the Public Staff's suggestion that the use of calling statistics be eliminated. As to the Public Staff's suggestion that CIFs be defined as customer calls divided by customer accounts, Southern Bell argued that this would be inaccurate and tend to overstate the CIF because of the use of accounts rather than lines. Southern Bell suggested that the use of access lines as the denominator would be more appropriate. As to the PMC definition proposed by the Public Staff, Southern Bell registered the same objection regarding lines versus accounts. Southern Bell further opposed the waiver of the use of CIFs and PMCs where TMC routes are involved. Southern Bell pointed out that the LECs would still be able to provide input data from LEC exchanges to the TMC exchanges. Southern Bell also opposed the waiver of the use of CIFs and PMCs where local calling routes are involved. Southern Bell said that, although it does currently include such data in its calculations of CIFs and PMCs, such data can be ascertained, although with some degree of difficulty. Southern Bell noted that nearly one-half of its access lines are currently being served by expanded local calling plans of some description. The Commission should exercise caution regarding any requests for EAS between points contained within an expanded local calling plan because of the stimulation effect of the discounts and seven-digit calling.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration of the filings in this docket, the Commission believes that it should continue to use CIFs and PMCs in reaching polling decisions and that the Commission should attempt to clarify the definitions of CIFs and PMCs.

The May 5, 1992, Order Promulgating Amendments to Rule R9-7 noted ". . .the Commission also agrees with the companies that calling studies are a valid indication of community of interest between two exchanges. While not perfect, such studies are a basic and measurable reflection of calling interest between exchanges. Their use will interject a greater degree of certainty and objectivity into the EAS proceedings." The Commission believes this reasoning is still sound and that these factors should continue to be used as a basis for evaluating EAS proposals.

However, the Commission agrees with the Public Staff that the rule should be amended to define CIFs and PMCs and to specify how each should be derived. Responses to the Commission's data request requesting types of calls included in calling data used to determine CIFs and explanation of how PMCs are calculated clearly indicated a lack of uniformity among the companies in this regard.

a. Community of Interest Factor (CIF): The Public Staff has recommended that this factor should be defined as the number of customer calls divided by the total number of customer accounts. This was concurred in by Central who supported the argument by stating that it believed the number of accounts, not the number of lines, better represents the amount of customers in an exchange. On the other side, Carolina, Southern Bell, and GTE all argued that CIFs should be calculated by dividing the number of customer calls by the total number of customer lines primarily based on: (1) the application of additional EAS charges would be applied on a per-line, not per-account basis; and (2) using customer accounts as the denominator would artificially inflate the CIF on a given route because multi-line business accounts (and their relatively higher amounts of usage) would be counted the same as single line residence and single line business accounts. The Commission believes Carolina's, Southern Bell's, and GTE's arguments to be more convincing. CIFs thus should be defined as the number of customer calls divided by the total number of customer lines with calls and lines as defined below.

<u>Lines</u> used in the calculation of the CIF should include the following types of customer lines/trunks: Key, PBX trunks, Centrex trunks, ESSX trunks, ISDN, simple business, and residence. This would capture the majority of residence and business-type lines/trunks over which toll calling is made.

The following type <u>calls</u> should be included when billed to a customer in the originating exchange: One-plus and operator-assisted MTS toll calls generated over the type lines/trunks listed above, as well as calls which are carried over the toll network on optional toll calling plans. These are toll calls which are generally carried over the toll network and are readily measurable.

b. Percentage Making Calls (PMC): The Commission believes that PMCs should be defined as number of access lines making calls divided by the total number of local customer lines/trunks. The same type of lines/trunks should be used as defined above.

The Commission further concludes that it is reasonable that Rule R9-7 should include a requirement of toll calling study results for interLATA EAS proposals and that toll calling studies from non-regulated telephone membership corporations (TMCs) should be requested by the LECs.

Moreover, the Commission concludes calling studies should be required in all situations where EAS is proposed regardless of size or lack of EAS additive.

However, the Commission does not believe that "special circumstances" should be defined in the rule. As noted by Carolina, it would be impractical, if not impossible, to list all the special circumstances that now exist. Rule R9-7(i) should also be amended to provide that a subscriber is entitled to as many votes as that subscriber has access lines.

Lastly, there are two additional issues upon which the Commission believes it should solicit additional comment. The first is whether, due to calling stimulation, there should be a higher CIF and PMC requirement under Rule R9-7(d) in cases involving two or more exchanges where both or all of the exchanges are subjects of local calling plans with seven-digit dialing and, if so, what the CIF and PMC standards should be. The second involves polling results. Currently, the Commission generally requests that polling results be broken down by business and residential categories. The first question with regard to polling results is whether polling results should be required in the rule to be reported by business and residential categories. The second question regarding poll results is whether Rule R9-7(i) should be amended such that a majority of ballots in <u>both</u> categories would have to be reached before an EAS proposal would be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That Rule R9-7 be amended as set out in Appendix A attached.

2. That all parties to this docket desiring to comment upon the issues identified in the last paragraph of the conclusions above do so no later than Friday, April 30, 1993, with reply comments due no later than Friday, May 14, 1993.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

1. Rule R9-7(b) Definitions is amended by adding a new Rule R9-7(b)(3) and Rule R9-7(b)(4):

"(3) Community of Interest Factor (CIF).--Number of customer calls (messages) divided by the total number of local customer lines/trunks. For the purpose of Rule R9-7, customer calls shall consist of: 1-plus and operator-assisted MTS toll calls and optional toll calling plan calls generated over Key, PBX trunks, Centrex trunks, ESSX trunks, ISDN, simple business and residence customer lines/trunks.

"(4) Percentage Making Calls (PMC).--Number of access lines making calls divided by the total number of local customer lines/trunks."

2. Rule R9-7(i) is amended by inserting a sentence after the first sentence to read: "A subscriber shall be entitled to as many votes as that subscriber has access lines."

3. Rule R9-7(d)(1) is rewritten as follows:

"(d) Toll Calling Studies.

(1) All proposals for EAS shall be accompanied by toll calling studies concerning the affected exchanges.

(a) Toll calling studies shall be for thirty-day periods, unless circumstances are shown to warrant a longer study period and shall be broken down into residential and business categories. Toll calling studies shall include information concerning community of interest factors (CIFs) and percentage of access lines making one or more calls (percentage making calls or PMCs) in the relevant time period.

(b) Upon request from the local exchange company, an interexcahnge carrier shall provide appropriate toll calling information for affected interLATA routes.

(c) When a telephone membership corporation (TMC) is involved in an EAS proposal, the TMC shall be requested to provide toll calling studies."

DOCKET NO. P-100, SUB 89

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of the Manner in Which Extended Area Service is Implemented in North Carolina	ORDER AMENDING RULE R9-7(i) AS TO REPORTING POLL RESULTS

BY THE COMMISSION: On March 25, 1993, the Commission issued an Order further amending Rule R9-7 and requesting comments on additional issues concerning the extended area service (EAS) rules. These additional issues were as follows:

1. Whether, due to calling stimulation, there should be a higher community of interest factor (CIF) and percentage making calls (PMC) requirement under Rule R9-7(d) in cases involving two or more exchanges where both or all of the exchanges are subjects of local calling plans with seven-digit dialing and, if so, what the CIF and PMC standards should be.

2. With respect to polling results:

a. Whether the rule should be amended to require that polling results be broken down by business and residential categories (this has hitherto been a usual and customary Commission request).

b. Whether Rule R9-7(i) should be amended such that a majority of ballots in <u>both</u> categories would be necessary before an EAS would be approved--i.e., concurrent majorities.

The Commission requested initial comments by April 30, 1993, and reply comments by May 14, 1993.

The following parties filed initial comments: ALLTEL Service Corporation (ALLTEL), Central Telephone Company (Central), the Public Staff, the Attorney General, Carolina Telephone and Telegraph Company (Carolina), GTE South (GTE), Southern Bell Telephone and Telegraph Company (Southern Bell), and North State Telephone Company (North State).

<u>Higher CIFs and PMCs for Seven-Digit Dialing Plans</u>

ALLTEL favored higher CIFs and PMCs in such areas and suggested that the CIFs should be at least 50% higher, with a more moderate adjustment for PMCs. ALLTEL argued that calling usually doubles in areas with such calling plans. ALLTEL also suggested, without providing particulars, that CIFs and PMCs should be increased in areas where there are optional local calling plans.

Central also favored a higher CIF and PMC standard. Current CIF standards should be doubled and PMC standards increased by at least 30%.

Carolina concurred in a higher CIF requirement to be, at a minimum, inversely proportional to the decrease in toll rates resulting from the local calling plan between or among the exchange involved in the EAS proposal. Thus, a 50% discount from toll rates should yield a doubling of the CIF requirement. The elimination of 1+ dialing should also be taken into consideration. Further, only the interexchange calling volumes per person not subscribing to a flat rate option of the local calling plan should be considered in the CIF calculation.

GTE indicated that higher CIFs should not necessarily be higher but noted that such standards could be justified due to stimulation.

Southern Bell believed that higher CIF and PMC standards were justified. Southern Bell pointed to empirical studies it had conducted showing much higher stimulation--roughly 1.5 times what existed before. Southern Bell recommended the following standards:

1. For intra-county, county-seat EAS proposals, a CIF of 2.5 or greater in the residential category or a CIF of 5.0 or greater in the residential and business categories combined.

2. For other intra-county EAS proposals, a CIF of 5.0 or greater in the residential category or a CIF of 6.25 or greater in the residential and business categories combined, and a PMC of 25% or greater.

3. For inter-county EAS proposals between exchanges with a common boundary, a CIF of 6.25 or greater in the residential and business categories combined and a PMC of 45% or greater.

4. For inter-county EAS proposals between exchanges without a common boundary, a CIF of 7.5 or greater in the residential and business categories combined and a PMC of 50% or greater.

Southern Bell does not believe that PMC standards need be increased.

North State did not believe that EAS should be considered where expanded local calling plans are in place.

The Attorney General opposed differential CIF and PMC standards as being unfair to subscribers in regional calling plan areas and impairing the movement toward EAS generally.

The Public Staff also opposed differential CIF and PMC standards. Stimulation merely reflects a partial unleashing of suppressed demand. Moreover, reduction of usage charges is just one of many factors that could cause PMCs and CIFs to change. While current information suggests that there has been some stimulation in regional calling plan areas, the amount of stimulation varies by route. There is no evidence of significant stimulation in PMCs. The Public

Staff furthermore cited concerns over the provision of accurate and timely CIF and PMC studies from regional calling plan areas. Rule R9-7 should be amended to provide specific instructions to the LECs for submitting reliable study results on a timely basis when requested.

Business and Residential Polling Results

ALLTEL opposed requiring both business and residential approval for EAS approval. ALLTEL seemed unclear regarding the revised Rule R9-7(i) which states that approval is to be based on individual poll results as well as unique circumstances.

Central argued that polling results should be reported for both residential and business categories but suggested that approval should depend on a majority of residential customers having voted "yes" and a majority of residential and business customers combined having voted "yes." Thus, a majority of business customers, many of whom have multiple votes because of multiple lines, would not have to vote "yes" as long as the combined vote total favored EAS.

Carolina concurred that polling results be reported by business and residential categories and recommended that, regardless of how business subscribers voted, EAS should not be implemented unless a majority of residential subscribers voted for it and the overall vote was positive.

GTE supported reporting both business and residential polling results and argued that there should be a concurrent majority requirement.

Southern Bell supported a separate reporting requirement as well as a requirement that there be a concurrent majority of positive votes in each category before a proposal will be approved. Business subscribers are far more likely to vote for EAS; and business customers with multiple lines could cause an overall positive vote even if most residential customers were negative.

North State concurred in a separate reporting requirement as well as concurrent majorities in both categories before EAS would be approved.

While the Attorney General believed that the reporting of poll results by residential and business categories is advisable, the Attorney General opposed a requirement for majorities in both categories, although the "vote in any one service category should be close to a majority."

The Public Staff opposed amending Rule R9-7 to require separate tabulation of polling results or to require concurrent majorities. The Public Staff noted that, in its review of poll results, the combined vote for or against EAS reflected the residential vote--not surprising, considering that 76% of all local access lines are residential and their poll responses tend to be higher than business.

Reply Comments

The following parties filed reply comments: Carolina, the Public Staff, and Southern Bell.

While agreeing with Southern Bell that higher CIF standards are necessary when seven-digit dialing optional calling plans exist, Carolina disagreed with Southern Bell as to how such standards should be determined. Carolina said that Southern Bell had proposed CIF standards 250% higher than otherwise. This figure was derived from call stimulation in optional calling plan areas. However, the call stimulation figures show tremendous variation. An average figure is too imprecise and unreliable. As an alternative, Carolina restated its own recommendation that the CIF requirement be inversely proportional to the decrease in toll rates. Thus, a 50% toll discount would double the CIF standard. Carolina also noted that its proposal excludes flat-rate local calling plan participants from any role in determining CIF standards.

Carolina applauded certain of the Attorney General's statements regarding equity between service classes and the benefits of EAS inuring to telephone users. Carolina added that these were good reasons why local calling plans are to be preferred over mandatory EAS.

As to the Public Staff's comments, Carolina argued that the Public Staff underestimated the stimulation effect of local calling plans, even while its statement about PMCs was essentially correct. Carolina noted that it had proposed that a favorable vote by residential subscribers would be necessary for an EAS to be passed, and it stated that not one of the 50 EAS polls cited by the Public Staff in its comments would have been reversed under Carolina's proposal. Residential customers should be given special consideration because they bear more of the EAS cost and derive fewer benefits. Neither the Public Staff's simple majority proposal or Southern Bell's concurrent majority proposal adequately protects residential customers' interests.

Southern Bell noted that there was considerable support for increasing CIF standards in local calling plan areas, but there was division as to how much. Southern Bell reiterated its view that CIF standards should be raised roughly by a factor of 2.5 as recommended in its April 30, 1993, comments. Southern Bell urged that an increase in CIF standards was necessary as a matter of equity and even equal protection because subscribers in local calling plan areas are situated dissimilarly from those outside such areas.

As to polling results, Southern Bell criticized the Public Staff for failing to recognize the potential impact of the new balloting procedure of one-vote-per-access-line. This change shifts power to business subscribers with many lines and can make the difference in EAS polls, while tending to dilute the influence of residential customers.

The Public Staff opposed changing CIF or PMC standards with respect to seven-digit regional calling plans. Should the Commission be inclined to change these standards, the Public Staff argued the only meaningful actual stimulation data was that of Central in its two six-month tracking reports in the Triangle J Regional Calling Plan and in its first six-month report in the Triad Regional Calling Plan. These data are not "contaminated" by options such as those offered by other companies. Central's reports indicate a message stimulation of 30% and no significant stimulation in PMC.

With respect to polling results, the Public Staff stated that the LEC's concerns that the business interest would overbear the residential is unfounded. The Public Staff also pointed out that in 38 out of 50 polls studied, the residence response level was greater than the business. This, coupled with the fact that business subscribers constitute only about 25% of all subscribers, makes it unlikely that business can vote in an EAS to which residential subscribers are opposed. Indeed, the more likely result under a concurrent majority requirement would be business voting down a proposal favored by residential subscribers. This could have happened under a concurrent majority requirement in two instances--Maxton in Docket No. P-7, Sub 744 and Acme in Docket No. P-7, Sub 765.

As a side matter, the Public Staff recommended that the Commission require GTE South, Southern Bell, North State, and Carolina to re-notice their regional calling plan customers regarding the usage-based nature of many local calling, since there has been a degree of customer inquiry and complaint and call detail is not routinely provided.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

There are two major questions being presented here:

1. Whether there should be a higher CIF and PMC standard under Rule R9-7(d) in cases involving two or more exchanges where both or all the exchanges are subject to seven-digit dialing local calling plans.

2. Whether Rule R9-7(i) should be amended to require concurrent majorities in both business and residential categories for approval.

A third issue, which is of relatively minor significance, is whether the rule should be amended to require that polling results be broken down by business and residential categories, as the Commission separately orders as a matter of course. Most parties supported this; the Public Staff did not. The Commission believes that Rule R9-7(i) should be amended to reflect and regularize this customary requirement.

As to appropriate CIF and PMC standards for EAS proposals concerning seven-digit local calling plan exchanges, the Commission notes that such local calling plans are at present experimental and geographically limited in nature and may or may not persist in their present forms. There is no compelling reason for the Commission to act now, especially in view of the fact that there are no EAS proposals pending between or among seven-digit local calling plan exchanges. If there were such a proposal, the Commission could utilize the special circumstances provision of Rule R9-7(d) to "approve, disapprove, narrow or limit" the EAS proposal. The Commission will take these comments under advisement and will consider acting on them if and when the seven-digit local calling plans become permanent.

The Commission further notes that while the principle of increased CIFs due to stimulation for such contexts may seem reasonable, there is no agreement as to what the appropriate increase should be. Carolina, for example, proposed an inversely proportional rule and criticized Southern Bell's proposal for a 250% CIF increase as an average based on highly variable stimulation data. The Public Staff, which opposes any CIF increase, pointed to Central's data in the Triangle J Regional Calling Plan, with 30% stimulation, as being the most reliable and "uncontaminated" data. There are thus a plethora of different rationales to support different levels of increases. One area where there does appear to be general (though not universal) agreement is that PMCs need not be raised. The data seems to show that the same people are making more calls rather than more people making more calls. Thus, the case for increasing the PMC standard appears relatively weak.

As to whether Rule R9-7(i) should be amended to require a concurrent majority in both residential and business categories, the Commission believes the rule should remain as it is. Such a requirement would tend to complicate EAS proposals, and the data does not appear to indicate that there is a problem with the business interest overbearing the residential interest. Southern Bell's concern that the one-vote-per-access line rule will unduly favor the business interest does not seem to have been borne out in the case of other companies that have been utilizing this practice. Southern Bell, in fact, seems to be the only major company that has not been using the one-vote-per-access line standard.

Other Issues. As is not uncommon, parties have raised various side issues and sought Commission action. Among them are the following:

1. In its March 25, 1993, Order, the Commission amended Rule R9-7(i) to provide that a subscriber is entitled to as many votes as that subscriber has access lines. The Public Staff, in its reply comments, pointed out that Southern Bell in its Boone example apparently counted NARs (Centrex) stations as one vote instead of counting only NARs trunks, as required by the rule. The Commission believes that it is clear that "access lines" in Rule R9-7(i) are defined in exactly the same way as lines used for the CIF and PMC calculations as outlined in the Conclusions section of the May 25, 1993, Order which reads:

> Lines used in the calculation of the CIF should include the following types of customer lines/trunks: Key, PBX trunks, Centrex trunks, ESX trunks, ISDN, simple business, and residence.

2. The Public Staff requested that Rule R9-7 be amended to provide specific instructions to LECs for reliable calling study results on a timely basis for seven-digit dialed routes. The Public Staff has indicated at least two instances involving Southern Bell and GTE in which it had difficulty obtaining requested data. Given the experimental nature of the seven-digit local calling plans, the Commission is not inclined to support a rule change at this time. Nevertheless, LECs should cooperate with the Public Staff to the best of their ability in providing information of this nature. If the Public Staff is experiencing difficulty in obtaining needed data, it should apply to the Commission for an appropriate Order; and the Commission is prepared to consider any reasonable request.

3. The Commission does not believe that the Public Staff's request for re-noticing customers that seven-digit dialed calls are subject to usage charges in the Triangle and Triad local calling plans is either germane to this docket or necessary.

IT IS, THEREFORE, ORDERED as follows:

1. That Rule R9-7(i) concerning polling results be amended by inserting the following sentence before the existing first sentence:

"EAS polling results shall be reported broken down by residential and business categories."

2. That the Public Staff's request regarding the re-noticing of Triangle and Triad Regional Calling Plan customers regarding the nature of their seven-digit calling be denied.

3. That the Public Staff's request that Rule R9-7 be amended to require timely information regarding calling studies involving seven-digit dialing local calling plan exchanges be denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Commissioner Sarah Lindsay Tate dissents.

DOCKET NO. P-100, SUB 103

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Financial and Operating Reporting Requirements for Telephone Companies	)	ORDER AMENDING RULE R9-9(A)(10) AND REVISING SCHEDULE 10 OF THE TS-1 REPORT

BY THE COMMISSION: Revised intraLATA toll settlement procedures (referred to as the "Transition Plan") were implemented on July 1, 1992. The Public Staff presented an agenda item at the Commission's Staff Conference on March 1, 1993, informing the Commission that the Transition Plan implemented for the intraLATA toll pool will require a change in the toll information required by Commission Rule R9-9(A)(10) as reported on Schedule 10 of the TS-1 Report and a change in said Rule.

The Public Staff recommended that Schedule 10 be revised to ensure that the necessary information will be reported by all Local Exchange Companies (LECs). Because the method of pooling was changed from an actual cost- and average schedule-based approach to an access-based compensation method, both average schedule and cost companies should be required to provide the toll information reported on Schedule 10. The Public Staff proposed that the revised Schedule 10 be adopted effective with the September 30, 1992, TS-1 Report filing; and that all LECs be required to file a revised Schedule 10 for each period for which these reports have already ben submitted beginning with the September 30, 1992, filing. The Public Staff also pointed out that Commission Rule R9-9(A)(10) will need to be amended to delete the language "average schedule companies only".

On March 3, 1993, the Commission issued an Order in this docket that set forth the Public Staff's proposal to amend Rule R9-9(A)(10) and revise Schedule 10 of the TS-1 Report and requested that comments on these proposals be filed within 30 days. The comment period has now expired. The Commission received one comment which came from Carolina Telephone and Telegraph Company stating that they did not object to the Rule amendment.

Based upon the foregoing, the Commission finds that it is appropriate to adopt the Public Staff's proposed revisions of Rule R9-9(A)(10) and Schedule 10 of the TS-1 Report.

IT IS, THEREFORE, ORDERED:

1. That Rule R9-9(A)(10) is hereby amended by striking the words "average schedule companies only". A copy of amended Rule R9-9(A)(10) is attached hereto, as Appendix A.

2. That the Public Staff's proposed revision of Schedule 10 of the TS-1 Report is hereby adopted effective with the September 30, 1992, TS-1 Report filing. A copy of revised Schedule 10 of the TS-1 Report is attached hereto, as Appendix B.

3. That all LECs are required to file a revised Schedule 10 for each period for which these reports have already been submitted beginning with the September 30, 1992, TS-I Report filing.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of April 1993.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

(SEAL)

For Appendix B See Official Copy of Order in Chief Clerk's Office.

APPENDIX A

RULE R9-9. FINANCIAL AND OPERATING REPORTING REQUIREMENTS FOR TELEPHONE COMPANIES

(A) All local exchange telephone companies shall file the following financial and operating information with the Public Staff and the Commission Staff:

. . . .

(10) Miscellaneous Information on Access Lines, Number of Employees, Common and Preferred Stock Dividends, and Toll Settlements

DOCKET NO. P-100, SUB 121

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Expanded Interconnection With Local Telephone Company Facilities	) ORDER) PROMULGATING) POLICY FAVORING) CHOICE

BY THE COMMISSION: On October 19, 1992, the Federal Communications Commission (FCC) released a Report and Order and Notice of Proposed Rulemaking, entitled In the Matter of Expanded Interconnection with Local Telephone Company Facilities (CC Docket No. 91-141) (hereinafter, "FCC Order"). The FCC Order requires Tier 1 Local Exchange Carriers (LECs) to offer expanded interconnection to all interested parties, permitting competitors and high volume users to terminate their own special access transmission facilities at LEC central offices. Tier 1 LECs are companies having annual revenues from regulated telecommunications operations of $100 million or more. The FCC requires that physical collocation be made available upon request for interstate special access services.

The FCC Order recognizes two reasons for exemption from the requirement for a physical collocation option. The first is if the LEC demonstrates that a specific central office lacks the physical space to accommodate physical collocation. The second is if the following exists:

> ... a formal decision by a state legislature or public utility regulatory agency, after proceedings allowing all interested parties a reasonable opportunity to be heard, in favor of virtual collocation rather than physical collocation for intrastate expanded interconnection, or in favor of allowing LECs to choose which form of interconnection to use for intrastate expanded interconnection. Exemption requests based on such final state decision must be submitted...

By letter dated December 11, 1992, the LECs in North Carolina have requested that the Commission address the question of whether special access expanded interconnection should be implemented either via physical or virtual collocation. According to the LECs, a decision and appropriate action by the North Carolina Utilities Commission must occur before February 16, 1993, in order to avoid an FCC mandate restricting intrastate special access interconnection to physical collocation arrangements. The LECs assert that inaction on the part of the state utility commission will result in FCC preemption relative to special access expanded interconnection.

On December 22, 1992, the Commission issued an Order Initiating Investigation and Requesting Comments on the issue of whether the Commission should adopt a policy in favor of virtual collocation rather than physical collocation for intrastate expanded interconnection or a policy in favor of allowing LECs to choose which form of interconnection to use for intrastate expanded interconnection. A copy of that Order was served on all LECs, all certificated interexchange carriers, (IXCs), the Attorney General, Public Staff, and Privacom. In addition, certain of the LECs were required to have a public notice of investigation published in newspapers of general circulation throughout North Carolina.

Comments were received from: ALLTEL Carolina, Inc., Heins Telephone Company and Sandhill Telephone Company (ALLTEL); Carolina Telephone and Telegraph Company (Carolina); Central Telephone Company (Centel); GTE South Incorporated and Contel of North Carolina, Inc., (GTE South); Citizens Telephone Company (adopting Comments of ALLTEL), Concord Telephone Company (Concord); Lexington Telephone Company (Lexington); North State Telephone Company (North State); BellSouth Telecommunications, Inc., d/b/a Southern Bell Telephone and Telegraph Company (Southern Bell); AT&T Communications of the Southern States, Inc. (AT&T); LDDS of Carolina, Inc. (LDDS); MCI Telecommunications Corporation (MCI); Sprint Communications Company L.P. (Sprint); The Public Staff; Carolina Utility Customers Association, Inc. (CUCA); and PrivaCom, Inc. (PrivaCom).

Initial Comments. All of the LECs with the exception of North State favored the Commission adopting a state policy of LEC choice as to the form of interconnection, with virtual collocation as an alternative. North State recommended virtual collocation.

Carolina argued that under GS 62-110 the Commission lacks the statutory authority to certify competitive access providers (CAPs) on an intrastate basis, and that, absent legislative action, CAPs must be restricted to operation on an interstate basis only. Carolina recommended that the Commission issue an order allowing the affected LECs to choose either virtual collocation or physical collocation to use at such time as intrastate expanded interconnection is allowed by law. In what Carolina viewed as a less satisfactory alternative, Carolina recommended that the Commission issue an order favoring virtual collocation. Carolina expressed concerns about FCC preemption and pressed the Commission to act to ensure that FCC preemption regarding mandatory physical collocation does not occur.

Centel also suggested that the Commission adopt a position in favor of LEC choice of providing physical or virtual collocation. Centel argued that the physical collocation position of the FCC is flawed in that there is no proof that physical collocation is necessary for the public interest to be served. Mandatory physical collocation is in conflict with the FCC's own earlier statement that virtual collocation is comparable. Furthermore the FCC action is an unwarranted taking of property, and may actually serve to undermine the FCC intent to promote competition. Centel states that the LECs can best manage interconnection arrangement to the benefit of end users and that, due to limited floor space availability and no requirement to construct facilities for collocation, the FCC action may deter new market entrants after the initial phase. Centel also argued that the Commission should take the position that tariffing of building space is not a proper function of the tariffing process and that physical collocation should not be required.

GTE asked the Commission to adopt a policy of LEC choice as between virtual and physical collocation, or in the alternative, adopt a virtual collocation policy. GTE cited several reasons for its position: A physical collocation policy will raise costs and reduce efficiency; mandatory physical collocation poses serious network security and reliability risks; and finally, a LEC option rule will best preserve this Commission's power to direct telecommunications policy.

Southern Bell stated it favored a policy -- both interstate and intrastate -- that permits a Tier I LEC to choose either virtual or physical collocation on a central office by central office basis. Southern Bell submitted that the Commission cannot permit competition in the access market unless the General Assembly specifically authorizes that competition, as it did with long distance, coin telephone service, and shared tenant service. Even before considering such competition, the Commission should consider the issues to which that competition gives rise including pricing flexibility, loss of subsidy to the basic residence exchange service and regulatory reform. Given the complexity of all of the issues, the Commission should not be forced to act precipitously. Southern Bell recommended that the Commission consider supporting NARUC's petition for reconsideration now pending at the FCC.

Several non-Tier I companies filed comments. ALLTEL thought it would have been preferable to limit the scope of this inquiry to Tier 1 companies and urged the Commission to exempt all non-Tier 1 LECs from any Commission requirement of collocation or of filing of intrastate collocation tariffs. Concord expressed concerns that the small companies which are exempted from the FCC's order will, through regulatory or market forces, be required to provide expanded interconnection in the future. Concord also expressed concern with safety and employees, and security and recommended that the Commission make physical collocation optional, not mandatory, for Tier 1 LECs. Concord further stated it does not believe that any party in this FCC proceeding has offered a compelling reason to require physical collocation over virtual collocation for LECs, but there have been serious concerns raised regarding the additional costs, and security and legal issues presented by physical collocation. Lexington encouraged the Commission to adopt a policy which would allow LECs to choose the form of interconnection which best fits that LEC's circumstances. North State stated it believes that a state policy in favor of virtual interconnection arrangements is in the public interest, removes undue burdens from the LEC, and approaches interconnection in a manner which has less far-reaching impact on the ratepayer.

AT&T argued that the real objective of the LECs is to obtain a pronouncement by this Commission of a state policy favoring virtual collocation which would exempt them -- for purposes of interstate services -- from the physical collocation requirement. AT&T stated it favored expanding access alternatives and it supports Commission action authorizing access competition in connection with intrastate service. AT&T further favors a requirement, in the event competitive access is authorized, that physical collocation be required to be offered by the LECs. However, AT&T believes that the narrow "collocation" question which the LECs are now pressing cannot reasonably be resolved in isolation from broader issues of competition in general, and encouraged the Commission to proceed to a broader generic hearing addressing the authorization of competitive access (including collocation), expanded local calling plans, and intraLATA competition.

LDDS and MCI supported the Commission adopting a policy of physical collocation. Both companies expressed concerns about the possible competitive advantage AT&T would have over its smaller rivals. MCI stated it believes that expanded interconnection should be accompanied by the implementation of certain safeguards to avoid the risk that expanded interconnection could adversely affect competition in the interexchange marketplace.

Sprint stated it does not take a position as to which form of collocation, physical or virtual, the Commission should adopt as its policy, and it does not oppose LECs choosing physical or virtual collocation. Sprint also urged the Commission to take such actions as may be necessary to insure that the terms and conditions governing the Commission's collocation policy does not favor one interconnector over another or physical collocation over virtual collocation. Further, Sprint urged the Commission to consider the safeguards set out by the

FCC in its order. In addition, Sprint stated that, to achieve the benefits of intrastate expanded interconnection, virtual collocation arrangements must be provided in a manner that is sufficiently comparable in quality to physical collocation.

The Public Staff argued that the Commission does not have the authority under existing statutes to authorize competition with the LECs in the provision of local exchange or intrastate access services and that enabling legislation would be required before the Commission could authorize provision of local exchange or intrastate special access by a competitive carrier. However, the Public Staff does not believe the Commission is precluded from reaching a policy conclusion at this time on the preferred means of intrastate expanded interconnection even though the Commission does not currently permit such interconnection. The Public Staff stated that based upon its review of the FCC docket, it believes that each LEC should be free to determine on an office-by-office basis the type of expanded interconnection which it will make available to interconnectors. This would enable LECs to offer virtual collocation to interconnectors where provision of physical interconnection would result in greater costs or inefficiency for the LEC. Since the increased costs and inefficiency would impact the interests of the basic local subscribers as well as the large telecommunications users, giving the LEC flexibility to choose which type of collocation it will provide would enable the LEC to better balance the interests of all of its subscribers.

CUCA believed that retention of the physical collocation requirement will not preclude the LECs from negotiating virtual collocation requirements with interested parties. Approval of any requested exemption from the physical collocation requirement could well preclude certain forms of competition which would be socially beneficial. CUCA further stated that in the event that the Commission authorizes reliance upon virtual collocation rather than physical, the competitive options to CUCA's member companies will be significantly reduced. The Commission should therefore not allow any "watering down" of the FCC's efforts in favor of competition in the absence of some overriding reason to do so. Since, to date, no overriding reason for abandoning the physical collocation requirement has been advanced by anyone, CUCA believes the Commission has no basis to permit any exemption from the physical collocation requirements at the present time.

PrivaCom, a competitive access provider (CAP), urged the Commission not to seek exemption from the FCC mandated physical collocation rules. PrivaCom further stated that it is not necessary for the Commission to establish virtual collocation as a viable service option because CAPs may find virtual collocation preferable to physical after exploring both options with LECs. The ability of CAPs to compete effectively for interstate access services is contingent upon their ability to gain expanded interconnection within the central offices owned and controlled by the LECs. Because LECs control these central offices, they occupy a bargaining position superior to the CAPs. PrivaCom argued that the considerable experience that has been gained with collocation in other states, and the voluminous record compiled in the FCC's collocation proceeding fully demonstrates that only a mandatory physical collocation standard can place interconnectors on competitively equal footing with the LECs. PrivaCom stated that inasmuch as North Carolina does not now permit competition for <u>intrastate</u> local access services, having a policy in place would conflict with existing North Carolina law and policy.

<u>Reply Comments.</u> Reply Comments were received from: Carolina, GTE, Southern Bell, AT&T, CUCA and Fibercom, Inc.

Carolina replied to PrivaCom's concerns about virtual collocation as being inferior to physical, and concerns regarding technological advances by indicating that these allegations are unsupported by the facts. Further, Carolina stated that PrivaCom's allegation that most states favor a physical collocation arrangement is simply untrue, a number of states support the policy of LEC choice, and NARUC has adopted a resolution favoring LEC choice. Carolina will provide collocation to all parties requesting it and on the same or similar terms and conditions. Furthermore, Carolina does not foresee a lessening of infrastructure development and technological advance if the Commission adopts a position of LEC choice.

In response to AT&T's comments, Carolina stated that AT&T's argument that collocation and intraLATA competition are inseparable is without basis as intraLATA competition is not directly related to collocation issues and should not be addressed in this docket.

Carolina concluded by reiterating its earlier recommendation that the Commission should issue an order allowing the affected LECs to choose either virtual or physical collocation on an office-by-office basis at such time as intrastate expanded interconnection is allowed by law, or in the alternative, but less acceptably to Carolina, an order requiring virtual collocation rather than physical collocation.

In its Reply Comments, GTE pointed out that PrivaCom's Comments made no attempt to justify a physical collocation rule in terms of the Commission's responsibility to safeguard ratepayers' interests. GTE also cautioned the Commission to avoid accepting claims that failure to act on collocation at the state level would not result in preemption of state special access interconnection policies and that it is a practical impossibility to limit the effects of interconnection implementation decisions to just the interstate or intrastate arena.

In response to Privacom's arguments that the actions of other state regulatory commissions and the FCC provide "incontrovertible evidence" to support adoption of a physical collocation requirement, GTE replied that these assertions were misleading and provide no basis for this Commission to forego issuance of its own policy. GTE also responded to PrivaCom's remarks that experience with virtual collocation in other jurisdictions has demonstrated its anticompetitive impact by indicating these statements are wholly unsupported by any facts and, to GTE's knowledge, no such problems have occurred. GTE further pointed out that the FCC Order was not unanimous, was introduced late in the FCC's rulemaking by three of the five FCC Commissioners and overrode the FCC's own staff recommendation.

GTE stated that most advocates of mandatory physical collocation did not adequately justify their preference for physical collocation. According to GTE, CUCA appeared to rely solely on the FCC's judgment that mandatory physical collocation is a competitive necessity, AT&T's concern seems to be with further introduction of competition in intrastate markets, rather than the specific issue of collocation, and MCI's filing appears to be motivated primarily by fear that AT&T will gain an undue competitive advantage in an environment of expanded special access competition. In response to PrivaCom's contentions that a virtual collocation option will result in less reliable CAP service, artificially inflate CAPs' cost, result in excessive litigation and stunt North Carolina's economic growth, GTE stated it believed such assertions to be untenable.

GTE also stated it believed there are no legal obstacles to adoption of a LEC option collocation policy and that nothing precludes the Commission from ruling on collocation at this time whereas the risks of inaction in this matter are simply too great. GTE concluded by urging the Commission to adopt a policy allowing LECs to choose between physical and virtual collocation in response to valid interconnection requests. The availability of a virtual collocation option is critical to assure the Commission's ability to guide the development of the intrastate special access market in accordance with state-specific conditions and social objectives.

Southern Bell recommended that the Commission adopt the Public Staff's recommendation and declare a policy allowing LECs to choose on an office-by-office basis between virtual and physical collocation in time to allow the LECs to seek an exemption from the FCC by February 16, 1993.

AT&T pointed out that it should be clarified that the FCC's proceeding does not entail preemption of any intrastate services and there is nothing in the FCC's decision that would prevent this Commission, at a later time, from adopting virtual collocation, or LEC choice, as a policy for intrastate special access. The FCC's deadline is designed to respond to existing state policies supporting competitive access for intrastate services. It is clear that a true competitive policy in this respect in North Carolina will not and cannot be put in place in the next two weeks and there is neither need or justification for immediate action by this Commission. AT&T recommended that the Commission proceed to address the North Carolina issues independently of the FCC's procedural schedule and at a pace which allows the relevant state issues to be aired and resolved reasonably and responsibly.

AT&T repeated that it is prepared to assist in pursuing a generic and broad-based docket on the full range of competitive issues facing the Commission but recommends that, for the present, the Commission refrain from any hasty policy pronouncements

CUCA suggested that the Commission should abstain from making any decision to grant or deny any exemption from the physical collocation requirement or to adopt a policy of mandatory physical collocation for use in this jurisdiction.

Fibercom urged the Commission not to adopt either of the policies proposed in its December 22, 1992, Order for the following reasons: The FCC order does not preempt state action; the FCC's collocation rule will not affect the intrastate rate base; there is no legitimate basis for LECs' alleged concern over security and network integrity; the FCC's collocation order does not represent an unlawful taking of LECs' property; physical and virtual collocation do not confer the same benefits on interconnectors; and competition for intrastate local access services is not permitted under North Carolina law.

WHEREUPON, THE COMMISSION reaches the following

CONCLUSIONS

After careful consideration of the filings in this docket, the Commission believes that the LECs should be given the choice of virtual or physical collocation as to interconnection with CAPs and other interconnectors.

The posture of this matter as it appears before the Commission at this time is somewhat unusual. The Commission agrees with those parties who have noted that the North Carolina statutes do not currently allow the certification of CAPs. The Commission also agrees with the Public Staff that the Commission nevertheless is not precluded by this from reaching a policy conclusion at this time on the preferred mode of intrastate expanded interconnection. The policy would simply apply to the provision of access at some future time.

The fact of the matter is that the FCC's decision favoring interstate physical collocation necessarily has intrastate implications. First, if North Carolina were to allow intrastate CAPs, the physical collocation preference of the FCC would tend to determine the preferred mode of intrastate collocation. Second, even in the absence of intrastate CAP certification, the preference for interstate physical collocation has implications for intrastate services and the cost of these services. Fortunately, the FCC has chosen to allow the states a window of opportunity in which to exercise what some parties have characterized as a "reverse preemption" -- that is, if a state favors a policy of virtual collocation or of choice with respect to intrastate interconnections, this policy will be determinative of interstate interconnection as well.

We believe that the Pennsylvania Public Utility Commission was directly on point concerning the importance of the central office to the telecommunications infrastructure and to the maintenance of effective service when it issued its December 19, 1992 statement of Policy favoring choice in this matter. The Pennsylvania Commission wrote:

> LEC central offices are fundamental components of the core telecommunication's infrastructure used to provide telephone service to the ratepayers. . . Thus we have a vital interest in ensuring that the LECs continue to maintain their ability to utilize the capacity of their central offices in order to meet the obligations to provide reliable and economical intrastate telephone service. (Pennsylvania Bulletin, Vol. 22, No. 5, December 19, 1992, p. 6034)

In view of the limited time that the Commission has in which to act, we believe that the more prudent course is for us to exercise the right of reverse preemption and enunciate a policy of choice for LECs for the reasons as generally set forth by the proponents of choice. Such concerns regarding physical collocation include:

1. Higher costs and reduced efficiencies pursuant to the forced reconfiguration of LEC central offices. A mandatory physical collocation policy could affect the intrastate rate base. With central office space preemptively

allocated to interstate interconnectors, LECs may well have to build or acquire new facilities to meet intrastate needs, thus increasing the cost of intrastate services.

2. Risks concerning network security and reliability.

3. Disruption of LECs' operations leading to a reduced ability to ensure reliable and affordable service.

4. Reduced ability by the LECs to meet long-term state needs and several objectives.

5. An erosion of the Commission's power to direct telecommunications policy.

Proponents of mandatory physical collocation, notably PrivaCom, have sought to deprecate these concerns. The Commission does not agree. Since the actual experience with collocation is minimal, the Commission believes it would be unwise to mandate one form of collocation at this time.

A flexible policy of permitting LECs to opt for either virtual or physical collocation for special access is the best way for the Commission to assure dependable and affordable telecommunications services in keeping with North Carolina consumers' needs. A LEC option policy will also allow this Commission to determine the contours of the access market in accordance with state-specific conditions.

This alternative will fit within any future Commission initiatives to foster development of the competitive special access market. This is true because the FCC's virtual collocation scheme affords technical interconnection arrangements equal to those associated with a physical collocation regime. Under virtual collocation, the LEC will designate an interconnection point near its central office that is physically accessible to both the LEC and the interconnector on nondiscriminatory terms. LECs and interconnectors would remain free to negotiate the key details of virtual collocation arrangements, allowing the parties to tailor rates, terms, and conditions to the type of central office equipment an interconnector wishes to use. The same arrangements will be made available to any similarly situated entity within the same central office.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby promulgate a policy of LEC choice with respect to intrastate expanded interconnection by CAPs and other interconnectors with LEC facilities.

2. That a copy of this Order be sent to the Federal Communications Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-100, Sub 21

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Audits and Analyses of the 1992 Annual Reports of Mid South Water Systems, Inc., Surry Water Company, Inc., H.C. Huffman Water Systems, Inc., Old South Lane Water System, Inc., and Lincoln Water Works, Inc.	) ORDER REQUESTING ASSISTANCE OF THE PUBLIC STAFF

BY THE COMMISSION: Regarding certain matters coming before the Commission in recent months concerning Mid South Water Systems, Inc. (Mid South) and Surry Water Company, Inc. (Surry), the Commission, in an attempt to evaluate the financial fitness of said companies, in conjunction with other information and data, examined several of Mid South's and Surry's annual reports previously filed with the Commission. Such examinations revealed that the subject reports were grossly deficient. At the request of the Commission, in some instances, revised reports were filed. However, certain of the revised reports were either found to be deficient or otherwise of concern to the Commission.

Several of the foregoing deficiencies and/or related concerns are set out (1) in the Commission's Order Revoking Temporary Operating Authority in Bradfield Phases III, IV, and V, Declaring Silverton Extension Unauthorized, and Scheduling Further Hearing on Bradfield II Certificate, issued on July 28, 1992, in the matter of Mid South's application for a certificate of public convenience and necessity to provide water and sewer utility service in Bradfield Farms and Britley Subdivisions, Docket No. W-720, Subs 96 and 108 and (2) in the Commission's Order Denying Franchise, issued on November 16, 1992, in the matter of Surry's application for a certificate of public convenience and necessity to furnish water utility service in Bishops Ridge Subdivision, Docket No. W-314, Sub 26.

Matters of concern relating to the financial conditions of Mid South and Surry are also addressed in the Commission's Order Denying Application For Franchise, issued on May 19, 1993, in the matter of Forsyth Water Company, Inc.'s (Forsyth's) application for a certificate of public convenience and necessity to furnish water utility service in the Bishops Ridge Subdivision in Forsyth County, North Carolina and for approval of rates, Docket No. W-1027. Such concerns were addressed in that Order because of the commonality of ownership of Mid South, Surry, and Forsyth. All three corporations are wholly-owned by Carroll and Mary Weber. Further, the Commission has also addressed its concerns regarding Mid South's financial well being in its Order Revoking Franchise in Bradfield Farms Phase II, issued on December 3, 1992, in the matter of Mid South's application for a certificate of public convenience and necessity to provide water and sewer utility service in Bradfield Farms and Britley Subdivisions, Docket No. W-720, Subs 96 and 108.

Based on the foregoing, including the findings and conclusions reached by the Commission in its Orders issued in the dockets identified hereinabove, the Commission finds and concludes that good cause exists to request assistance from the Public Staff in resolving continuing concerns pertaining to the financial fitness of all public utilities which are wholly-owned by Carroll and Mary Weber.

Therefore, the Commission hereby requests that the Public Staff (1) investigate, audit, analyze, and evaluate the current financial condition of Mid South, Surry, H.C. Huffman Water Systems, Inc. (Huffman), Old South Lane Water System, Inc. (Old South Lane), and Lincoln Water Works, Inc. (Lincoln) and (2) prepare and file a report(s) with the Commission setting forth its findings, conclusions, and recommendations, if any, regarding the current financial fitness, or the absence thereof, of the aforesaid companies. In responding to this request, as a minimum, the Commission further requests that the Public Staff do the following specific things:

(1) Perform financial audits and investigations of the books, records and reports, and take whatever other action it may determine to be appropriate, such that the Public Staff can certify to the Commission that the 1992 annual reports of the subject companies filed with the Commission do in fact fairly present the financial position and the results of operations of those companies at December 31, 1992, and for the 12-month period ended December 31, 1992, respectively, in accordance with generally accepted accounting principles and the rules, orders, practices, and procedures of this Commission;

(2) Take such action as is required to determine (a) whether the companies have complied and are complying with the Commission's rules, practices, and procedures concerning the "gross up" of contributions in aid of construction (CIAC) and (b) whether any one or all of the companies might be potentially liable for the payment of state and federal income taxes on CIAC received subsequent to enactment of the Tax Reform Act of 1986, and, if so, provide to the Commission an estimate of any amounts that might be due including tax, penalty, and interest. Also, please indicate whether a statute of limitations might limit the period of exposure on any potential liability. If it is concluded that a statute of limitations does apply, please identify such a provision and explain the reasoning for its applicability;

(3) During proceedings concerning Forsyth's application for a franchise to serve the Bishops Ridge Subdivision, Docket No. W-1027, it came to the attention of the Commission that Carroll and Mary Weber had secured loans by pledging the assets of certain utility systems without having sought or received the Commission's approval for such action (See the Commission's Order Denying Application for Franchise, issued on May 19, 1993, in Docket No. W-1027). The Public Staff is requested to take such action as is required to determine whether the pledging of such assets will jeopardize the future provision of public utility services by Mid South, Surry, Huffman, Old South Lane, and Lincoln. Further, it is requested that the Public Staff examine the issue and take a position as to whether the companies or the Webers should be fined for having pledged public utility assets without having first obtained Commission approval; and

(4) The proprietary information filed in Docket No. W-1027 indicates that Carroll and Mary Weber are guarantors of certain of Mid South's outstanding debt. Such debt is substantial. Therefore, the Commission believes that it is germane to this undertaking for the Public Staff to assess the financial fitness of Carroll and Mary Weber and to report its findings to the Commission, and it is hereby requested to do so.

IT IS, THEREFORE, ORDERED that the Public Staff shall be, and hereby is, requested to provide assistance to this Commission in the manner and for the purposes as described hereinabove. It is further requested that the Public Staff complete the audits, investigations, and analyses as requested herein and file its report(s) with the Chief Clerk of the Commission no later than September 30, 1993.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of May 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. E-13, SUB 155

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Nantahala Power and Light Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity Pursuant to G.S. 62-102 for Construction of Nantahala/Marble 161 KV Transmission Line	)	ORDER DENYING REQUESTS AND MOTION FOR ADDITIONAL HEARING IN ANDREWS

BY THE COMMISSION: There are requests pending in this docket that the Commission schedule a public hearing in Andrews, Cherokee County, to consider additional evidence relating to the concerns of local citizens about the proposed route of Nantahala's new transmission line. The Commission received a request for an additional hearing from Walter Bauen, an intervenor of record in this Docket on January 20, 1993, and from the Cherokee County Board of Commissioners on February 11, 1993. Attached to the letter of the Cherokee County Board were supporting petitions from approximately 130 residents of Cherokee County.

On February 15, 1993, the Attorney General and the Public Staff filed a Joint Motion requesting a public hearing in Andrews to consider additional testimony from the local citizens. In support of their Joint Motion, the Public Staff and the Attorney General cited "appreciable interest" that has developed in the community since the Commission's hearing on January 5, 1993. The Joint Motion also noted that no public hearing was conducted in Cherokee County.

Nantahala filed Responses to the request of Mr. Bauen on January 27, 1993, and to the Joint Motion of the Attorney General and Public Staff on February 16, 1993. In each Response, Nantahala requested that the Commission issue an Order denying the motion and requests for a local hearing in this proceeding. In support of its Responses, Nantahala recited that it has complied in all respects with the requirements of G.S. 62-100 et. seq. with respect to the filing of the application, the giving of public notice, and participating in a full evidentiary hearing. Nantahala contends that the proponents of an additional hearing have not established substantial cause to grant such request.

Upon consideration of the requests and Joint Motion for an additional hearing in Andrews, the Responses thereto of Nantahala, the entire record in this docket, and the requirements of G.S. 62-100 et. seq., the Commission is of the opinion, and so concludes, that the requests and motion for an additional hearing in Andrews should be denied.

In support of its decision, the Commission specifically concludes as follows: Prior to the enactment of G.S. 62-100 et seq. in 1991, the Commission heard and decided transmission line siting cases in a proceeding under the complaint statute, G.S. 62-73. As a result of the shortcomings associated with this procedure, a number of interested parties, including the Public Staff, the Attorney General, and the electric utilities, worked together to secure the enactment of G.S. 62-100 et. seq. This legislation for the first time provided a uniform and orderly procedure for the siting of electric transmission lines in North Carolina with a capacity of at least 161 kilovolts. The new statute establishes a timetable governing the application procedure; the times for notice, intervention, and hearing are expressly set out. The Commission is required to issue an order on each application within 60 days of the conclusion of the hearing, which time may be extended by the Commission "for substantial cause." G.S. 62-104(c).

A major defect under the old complaint procedure which was addressed by the new legislation was the giving of notice to the public. The new statute expressly sets out the manner in which notice is to be given to the public; publication of notice must be made in local newspapers of general circulation a minimum of three times. Moreover, the statute also requires that the application be served on State and local governments, including <u>each</u> county and municipality through which the proposed line may be constructed. An examination of the official file in this docket discloses that Nantahala has satisfied all notice requirements of the new statute. Public notice of Nantahala's application was published in the <u>Franklin Press</u> on September 30, October 7 and October 14, 1992; the <u>Andrews Journal</u> on September 30, October 7 and October 14, 1992; and the <u>Cherokee Scout</u> on September 30, October 7 and October 14, 1992. In addition, Nantahala has gone beyond the requirements of the statute by conducting public informational meetings with respect to the Application from 2:00 p.m. until 8:00 p.m. at Rowlin Church Fellowship Hall in Macon County on October 12, 1992, and at the Andrews Community Center from 2:00 p.m. until 8:00 p.m. on October 13, 1992.

With respect to the request of the Cherokee County Board of Commissioners, the Commission especially notes that, pursuant to the statutory requirement that notice of the application be served on each county and municipality through which the proposed line may be constructed, Nantahala served copies of its application on the Cherokee County Commissioners and County Manager Todd Reese, the Macon County Board of Commissioners, and the Town Manager of the Town of Andrews at the time Nantahala's application was filed on September 18, 1992. No response to this direct notice or to the public notice was made by any of the local governmental bodies until more than one month after the January 5, 1993, evidentiary hearing was concluded.

Consequently, the Commission is satisfied that Nantahala has met both the letter and spirit of G.S. 62-100 et. seq. with respect to the giving of notice to the public and to the affected county and municipal governments. Sufficient time elapsed between the giving of notice in September and October 1992 and the date of the hearing on January 5, 1993, in order for any person or local government concerned about the transmission line to file appropriate motion for intervention and request for a local hearing. Only one person, Walter Bauen, filed a petition to intervene, which was allowed. Mr. Bauen appeared at the January 5, 1993, hearing and offered testimony.

In their Joint Motion, the Attorney General and the Public Staff affirmed their commitment to the "orderly process" provided through G.S. 62-100 et. seq. and recognized "that there must be a cut-off point in considering cases such as this one in order to enhance fairness to all parties as well as to enhance efficiency in disposing of cases." Nonetheless, because of the "appreciable interest" in the proposed route which has developed in the community since the hearing on January 5, 1993, the Attorney General and the Public Staff state that a hearing should be scheduled locally. The Joint Motion further states, however, that it "may not be clear at this point how the additional evidence might be material. . . " The Commission agrees with the Attorney General and the Public Staff that the request of local elected officials "is entitled to great weight", but as pointed out above, the Commission is of the opinion that proper statutory notice was given to the local governmental bodies in this case for them to make a timely response.

The Commission has carefully considered all of the requests for an additional hearing and is of the opinion that they failed to show "substantial cause" for scheduling an additional hearing. An allegation that controversy "seems to be developing" with respect to the siting of the proposed line, without more, is insufficient to establish substantial cause.

In view of the new legislation enacted in 1991, the compliance by Nantahala with the requirements of the statute including the giving of notice, and the public hearing held on January 5, 1993, in which Mr. Bauen and others appeared and testified, the Commission is of the opinion that the requirements of the statute have been met and that there is no substantial cause to schedule an additional local hearing in the Andrews area.

IT IS, THEREFORE, ORDERED that the requests and Joint Motion for an additional hearing in the Andrews area in this docket be, and the same hereby are, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-13, SUB 155

In the Matter of Application of Nantahala Power and Light Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity Pursuant to G. S. § 62-102 for Construction of Nantahala/Marble 161 KV Transmission Line	)	ORDER ISSUING CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY

HEARD: Tuesday, January 5, 1993, at 9:30 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner J. A. Wright, Presiding; Chairman William W. Redman, Jr.; Commissioners Sarah Lindsay Tate; Robert O. Wells; Charles H. Hughes; Laurence A. Cobb, and Allyson K. Duncan

APPEARANCES:

For Nantahala Power and Light Company:

Robert W. Kaylor, Bode, Call & Green, Post Office Box 6338, Raleigh, North Carolina 27628-6338

For the Public Staff:

Paul L. Lassiter, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

William B. Crumpler, Associate Attorney General, Department of Justice, 430 North Salisbury, Raleigh, North Carolina 27611

Walter Bauen, Post Office Box 1449, Andrews, North Carolina 28901 (appearing pro se)

Lawrence I. Thorpe, 1301 Hightower Trail, Suite 260, Atlanta, Georgia, 30350 (appearing pro se)

BY THE COMMISSION: On September 18, 1992, Nantahala Power and Light Company ("Nantahala" or the "Company"), filed an application pursuant to G. S. § 62-102 for a certificate of environmental compatibility and public convenience and necessity to construct approximately 17 miles of new 161 KV transmission line from the Nantahala Hydro Plant substation to a new substation in the community of Marble in Cherokee County, North Carolina.

On September 30, 1992, the Commission issued an Order Scheduling Hearing for a Certificate of Environmental Compatibility and Public Convenience and Necessity, approving Nantahala's Summary of Application pursuant to G. S. § 62-104, and scheduling a hearing in Raleigh for January 5, 1993.

On October 22, 1992, the Attorney General filed a Notice of Intervention.

Motion for Intervention was filed by Walter Bauen on November 4, 1992, and the intervention was allowed by Commission Order of November 10, 1992.

On December 28, 1992, Motion for Intervention was filed by Lawrence I. Thorpe, President of Hamilton Development Corporation. The intervention of Lawrence I. Thorpe, individually, was allowed without objection by the Commission on January 5, 1993.

At the hearing, the Company filed Affidavits of Publication showing that public notice had been given as required by G.S. § 62-100 et seq.

The case came on for hearing as ordered on January 5, 1993. Testimony was received from public witnesses Nord Davis and Dr. Scott Priebe. Nantahala presented the direct testimony and exhibits of E. N. Hedgepeth, President and Chairman of the Board of Nantahala; N. E. Tucker, Jr., Executive Vice President of Nantahala; and Dwight M. Hollifield, Manager of Transmission Siting and Landscape Architecture, Duke Power Company. In addition, Nantahala introduced the testimony of J. Robert Siler, Senior Scientist, Duke Power Company; Larry L. Olmsted, Manager, Scientific Services Station, Duke Power Company; Paul E. Brockington, Jr., Archeologist and President of Brockington and Associates, Inc.; and Dr. Patrick A. Miller, Professor of Landscape Architecture at Virginia Polytechnic Institute and State University. The testimony of witnesses Siler, Olmsted, Brockington and Miller was submitted via affidavit pursuant to G. S. § 62-68. Neither the Public Staff nor the Attorney General presented evidence. Intervenor Lawrence I. Thorpe testified on behalf of himself, and Intervenor Walter Bauen testified in his own behalf. Nantahala then presented the rebuttal testimony of Henry Parker, Professional Engineer, Duke Power Company.

All parties to this proceeding were provided an opportunity to file proposed orders with the Commission. Nantahala filed its Proposed Order on February 19, 1993. No other party filed a proposed order.

After the hearing on January 5, 1993, the Commission received several requests for a public hearing in Andrews, Cherokee County, to consider additional evidence relating to the proposed route of Nantahala's transmission line. The Commission received a request for an additional hearing from Walter Bauen on January 20, 1993, and from the Cherokee County Board of Commissioners on February 11, 1993. On February 15, 1993, the Attorney General and the Public Staff filed a Joint Motion requesting a public hearing in Andrews to consider additional testimony from local citizens. Nantahala filed responses to the request of Mr. Bauen on January 27, 1993, and to the Joint Motion on February 16, 1993. In each response, Nantahala requested that the Commission issue an Order denying the Motion and request for a local hearing. On February 23, 1993, the Commission issued an Order denying the requests and Joint Motion for an additional hearing in Andrews.

Based upon the Company's verified application, the testimony and exhibits received into evidence at the hearing, and the record as a whole in this docket, the Commission now makes the following:

FINDINGS OF FACT

1. Nantahala's application was properly filed in accordance with G. S. § 62-102, and Nantahala properly served all parties in accordance with G. S. § 62-102(b).

2. No county or municipality filed with the Commission, or served on Nantahala, the provisions of any ordinance that might affect the construction, operation, or maintenance of the proposed line, as required by G. S. § 62-106.

3. Nantahala's proposed 161 KV transmission line from the Nantahala Hydro Plant to a new 161-34 KV substation near the community of Marble in Cherokee County is needed prior to the winter of 1994/1995 because existing electrical distribution facilities cannot maintain service reliability and quality, nor supply future growth, in the Andrews/Marble area of Cherokee County, North Carolina.

4. The proposed route is superior to other routes considered and evaluated in the context of the array of environmental, land use, and visual factors which led to its selection.

5. No party opposing the route proposed by Nantahala presented an alternative location for the proposed transmission line.

6. Nantahala's Transmission Facility Siting Study and Environmental Report, introduced as Hollifield Exhibit No. 1, describes the environmental consequences of the proposed transmission line. No significant, long-term environmental impact will occur as a result of the proposed action, and no deterioration of the environment surrounding the project will result.

7. The estimated cost of the Nantahala Marble 161 KV line is approximately $6.9 million.

8. Prior to construction, Nantahala must obtain a special use permit from the United States Forest Service; Erosion Control Plan Approval from the North Carolina Department of Environment, Health and Natural Resources; a Section 404 permit from the United States Army Corps of Engineers; Transmission Line Road Crossing Permits for each public road crossing from the North Carolina Department of Transportation; and driveway permits for each access road entrance onto a public road from the North Carolina Department of Transportation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

G. S. § 62-102 sets forth the requirements for an application for a certificate of environmental compatibility and public convenience and necessity. Nantahala's application in this proceeding, filed September 18, 1992, contains all of the information required by G. S. § 62-102. No party to this proceeding presented any evidence to the contrary. Accordingly, this finding is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G. S. § 62-106 provides a mechanism for a municipality or a county to notify the Commission and Applicant of the provisions of any ordinance that might affect the construction, operation, or maintenance of the proposed transmission line. Pursuant to G. S. § 62-102, Nantahala properly notified all counties and municipalities on the proposed route of the line, and no county or municipality filed notice with the Commission or with Nantahala of any ordinance that might affect the construction, operation, or maintenance of the proposed transmission line. Accordingly, Nantahala fully complied with the provisions of G. S. § 62-102 and § 62-106 with respect to this Application.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is found in the testimony of Company witnesses Hedgepeth and Tucker and Intervenor witnesses Thorpe and Bauen.

Company witness Hedgepeth testified that Nantahala serves approximately 4,600 customers in Cherokee County, and Nantahala's service area consists of approximately 140 square miles of predominantly rural territory with rugged mountainous terrain. The only incorporated town in Cherokee County served by Nantahala is Andrews with a population slightly under 1,300. Witness Hedgepeth testified that peak loads in the Andrews/Marble area have exceeded 25 MVA and are growing in excess of 3.5% on an annual basis, and that the entire service area was served by a radial 34 KV distribution line, originating at the Nantahala Hydro Plant substation some 17 miles northeast of Marble. Witness Hedgepeth further testified that given the length of the circuits and the load in the Andrews/Marble area, the existing electric distribution facilities could not maintain service reliability and quality nor supply future growth. Without the new transmission line, Nantahala could not provide the type of service necessary to support industry expansion in the Andrews/Marble area.

Nantahala witness Tucker testified that in 1989, Nantahala began a program to rebuild and improve its bulk power transmission system in order to enhance the reliability and quality of service to its customers. Witness Tucker testified that the transmission system was largely radial resulting in only one source to major load centers, that the outage of one line could result in loss of power to a large group of customers, and that many facilities were approaching loading limits and were aged and in need of major maintenance. Witness Tucker testified that the Andrews/Marble area was the only major load center on Nantahala's system that was not served from a transmission line. Witness Tucker testified that the area was currently served by two radially-fed 34 KV distribution circuits, that one circuit had a line capacity of 33.1 MVA, and that the other had a capability of only 18.5 MVA. Witness Tucker testified that an outage of the larger line during peak times would result in interruption of service to approximately 4,100 residential and 500 commercial/industrial customers.

Witness Tucker testified that the soluthon to the power supply-power quality problems in the Andrews/Marble area was to construct a new 161-34 KV substation near Marble and a double circuit 161 KV line to serve it. Witness Tucker testified that the double circuiting was proposed because it would be the only transmission source serving the area and because the line crossed miles of rugged mountainous terrain. Witness Tucker further testified that the proposed transmission line would assure adequate and reliable service by reducing the existing burden on the distribution facilities; by providing line capacity so that a scheduled or unscheduled outage on one circuit would not result in prolonged outages to customers; by reducing line losses and voltage drops, sags, and transients, thereby improving the service quality; and by providing capacity to future load growth and providing the increased reliability associated with a transmission supply rather than a distribution supply.

Witness Tucker testified that several alternatives to the proposed line had been investigated. These alternatives consisted of upgrading the existing 34 KV circuits from the Nantahala Hydro Plant to the Andrews area, installing a 66 KV line from the Nantahala Hydro Plant to the Marble area, and installing a 66/34 KV substation in Marble. Upgrading the existing 34 KV circuits was rejected because of the lower capacity and reliability of a distribution supply, and because load growth would exceed the capacity of a distribution line in the reasonably near future. In addition, Witness Tucker testified that transformer capacity would be needed at the Nantahala Hydro Plant and that substation expansion would be needed under any alternative, negating a major portion of the cost advantage of a lower voltage supply. Further, a distribution supply would not improve line loss problems, nor would it measurably improve Nantahala's ability to supply future load growth and quality of service improvements needed for industrial expansion and service in general. Witness Tucker testified that 66 KV was not currently available at the Nantahala Hydro Plant; and that to exercise that alternative, a 161-66 KV substation would be needed at the Nantahala Hydro Plant, a 66-34 KV substation would be required in the Marble area, and the cost of the additional substation facilities would exceed the cost savings of constructing a 66 KV line rather than a 161 KV line. Witness Tucker testified that the 161 KV transmission line was selected because multiple 161 KV sources were available at the Nantahala Hydro Plant, requiring only limited substation work which would minimize the cost of the substation facilities required to supply adequate electrical power to the Andrews/Marble area; and that a new substation in the Marble area, served by a new 161 KV line, would provide a transmission source of delivery near the anticipated load centers, resulting in adequate reliability for existing and anticipated loads in the area well into the future.

In addition to these alternatives, Nantahala considered construction of an underground 161 KV line, but rejected this alternative as it would require construction of an underground excavation trench approximately 6 feet deep and 10 feet wide for the entire length of the corridor. Further, the cost of underground construction for a 161 KV line was estimated to be $6 million per mile, compared to overhead construction of approximately $410,500 per mile.

With regard to tower structures, Nantahala evaluated alternative structure types, such as single-shaft steel pole structures, but selected lattice steel structures, since construction of single shaft steel poles would be extremely difficult and costly because of excavation requirements for foundations in the range of 18 to 30 feet backfilled with concrete, versus excavations of 8 to 12 feet deep backfilled with excavated material for lattice steel towers. Conductors being proposed for the line will be 795 kcm, 16/7 aluminum conductor, steel reinforced (ACSR), one per phase. All conductors will be non-specular to reduce reflectivity and to better blend into the adjacent backgrounds. Towers on the line will be spaced 900 feet apart, on average, and will range in height from 99 to 170 feet, based on preliminary engineering. Spans over deep gorges will range from 2,500 to 2,800 feet in length. Clearing will occur in portions of the forest areas on the 100 foot wide right-of-way, but wherever clearance from tree tops to the lowest conductor at maximum sag is 25 feet or more, the trees will not be cut.

Witness Tucker further testified that because existing loads and load growth in the Andrews/Marble area must be served from long radial distribution lines, the new Marble substation was needed as soon as possible; and that due to lead times on certain equipment and the construction times necessary to complete the substation and transmission line, the construction on the project needed to begin in September 1993 in order to meet an in-service date prior to the winter 1994/1995 load.

Intervenor witnesses Thorpe and Bauen generally did not question the need for the proposed transmission line, and neither witness produced direct testimony contradicting the need for the proposed line. Intervenor Bauen, through cross-examination of Nantahala witnesses Hedgepeth and Tucker, attempted to demonstrate that 161 KV transmission was not necessary in order to enhance the reliability of service to the Andrews area. Witness Tucker testified that reliability and quality of service could not be maintained with a distribution supply, especially for industrial customers. Neither Intervenor Bauen nor Intervenor Thorpe offered any direct testimony that 161 KV was not the proper voltage for the proposed line.

The Commission has carefully considered the evidence presented on this matter and concludes that Nantahala has presented overwhelming uncontradicted evidence that the proposed solution to its power supply/power quality problem in the Andrews/Marble area is to construct the proposed 161-34 KV substation near Marble and the proposed double circuit 161 KV line to serve it. Although Intervenor Bauen attempted to elicit through cross-examination that the proposed 161 KV line provided more voltage than would be necessary under current conditions, Nantahala witness Tucker rebutted this assertion by testifying that simply upgrading the distribution line would not provide enough capacity into the future and that transmission source, not enhanced distribution source, was needed for the Andrews area. Nantahala witness Tucker testified that Intervenor Bauen's suggestion to upgrade the distribution line would result in additional "H"-frame type towers having to be constructed, and more right-of-way having to be cleared, and would eventually require another circuit to provide reliability. Accordingly, the Commission is of the opinion that the proposed 161 KV transmission line is needed for reliability and future growth and that need exists for this project to be completed prior to the winter of 1994/1995.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 AND 5

The evidence for these findings of fact is found in the testimony of Company witnesses Hollifield and Miller and Intervenor witnesses Thorpe and Bauen.

Nantahala witness Hollifield testified that his responsibilities at Duke Power Company included route selection for transmission lines and site selection for substations. Witness Hollifield testified that Nantahala contracted with Duke to conduct a route selection study and recommend a preferred route for the Nantahala to Marble 161 KV line and that a detailed summary of the study and its results was contained in Hollifield Exhibit No. 1, the Nantahala-Marble 161 KV Line Transmission Facility Siting Study and Environmental Report ("Siting Study"). Witness Hollifield testified that his team defined a 76.97 square mile study area through which the route for the proposed line would be selected. Witness Hollifield testified that areas beyond the study area were excluded from consideration as a result of extremely steep topography, difficult access for construction purposes, and increased impacts to vegetation resources which would result from transmission line construction through remote, wooded regions.

Witness Hollifield testified that his team collected environmental and land use data for the study area from local, state, and federal agencies, and from extensive in-field investigations. The data comprised 76 data subsets, and each subset was assigned a weight factor to represent its individual influence on transmission line routing. The data was then entered into a computerized Geographic Information System, and various "data layer" maps were developed. The "layers" were combined to produce a single map which indicated the combined influence of all the data on transmission line routing, and that this map, called a suitability composite, showed the areas with highest constraint to routing, the areas with lowest constraint, and the full range of constraint conditions between. Figure 5 of Hollifield Exhibit 1 was introduced to illustrate this process.

Witness Hollifield then testified that the suitability composite was used to develop a series of 26 interconnected route segments, called links, through relatively low constraint areas. These links were examined in the field to confirm accuracy, and finally combined in a way that formed 14 alternative routes for further evaluation. Fifty-three evaluation factors were used to compare the 14 routes. The evaluation factors were grouped in seven categories, and assigned weights to represent their relative importance within the category. The factors most sensitive to transmission line routing within each category were given weights of 10; the least sensitive were given weights of 0. Physical quantities associated with each of the 14 routes (miles, acres, numbers of streams, roads, residence, etc.) were multiplied by factor weights within each of the 7 categories, and the results were added to arrive at a total score for each route within each category. Witness Hollifield then testified that based on the total category score, each route was ranked from best to 10th best in each category, and that these ranks were carried forward to a matrix containing 14 routes. The 7 category ranks for each route were added together to produce final evaluation scores, and the routes with the lowest totals were ones which minimized environmental, cultural, aesthetic and land use impacts across the 7 evaluation categories. The route selected, Route 4 as shown on Table 4 of Hollifield Exhibit 1, ranked best among the 14 routes evaluated.

Witness Hollifield testified that in addition to being the best route among the 14 evaluated, Nantahala was committed to significant techniques which would serve to minimize the line's visual and environmental impacts if the proposed route received approval. These techniques included the use of darkened, galvanized lattice structures, the use of non-specular conductors, background screening techniques, and special clearing techniques.

Witness Hollifield further testified that the most sensitive area along the proposed route was the Gipp Creek Watershed. Gipp Creek has been designated an outstanding resource water, and its watershed carries a North Carolina natural heritage area designation. Witness Hollifield testified that carefully planned construction techniques would prevent any impacts to the sensitive Gipp Creek Watershed because of line location, tower placement, the absence of clearing in the watershed, and the absence of access roads in the creek's drainage.

Nantahala witness Miller, an expert in the field of visual analysis, testified that the use of visual probability as a criterion to assess the potential visibility of a proposed power line was a concept that had been developed by Duke Power Company. Witness Miller testified that the extent of visibility and the visual contrast of the proposed line with the landscape was evaluated at scenic overlooks, residences, road crossings, and railroads, and that siting of the line was adjusted to minimize visibility and visual contrast from those areas. Witness Miller testified that in cases where there was concern of the extent to which the proposed line was visible from particular points along the route, computer-generated visual simulations were constructed, and that these visual simulations provided a mechanism for accurately checking the extent to which the proposed line would be visible from particular points. Witness Miller testified that the use of computer-generated simulations and photo simulations assured that the visual analysis work performed in the study was accurate and valid, and that visual considerations were an explicit and separate evaluation category that was given equal importance to the other categories in the final route selection.

Intervenor witness Thorpe objected to a segment of the proposed line that would cross in proximity to and across his property on the grounds that the line was being located too close to the town of Andrews and to residences in and around the town of Andrews, and on the grounds that the proposed route of the line presented potential health hazards as well as visual and environmental damage. Witness Thorpe testified that his property was located along Britton Creek, a creek north of the town of Andrews and between Gipp Creek and Beaver Creek. Witness Thorpe suggested that a better route for the line would be for the line to circumvent to the north of his property, follow Tatham Gap Road into United States Forest Service property, and eventually exit the Forest Service property near the proposed Marble substation. Witness Thorpe testified that he had not proposed a specific alternative route that the Commission could consider in this proceeding, and that he had not made an environmental, habitat, or water resource study with respect to his suggestion that the proposed route be moved north of his property and into the Forest Service property.

Witness Thorpe testified that the North Carolina Department of Transportation had proposed a highway that would eventually connect between Waynesville, North Carolina, and Andrews, and that if the highway were actually constructed in its presently proposed location, his development adjacent to Britton Creek would be severely damaged. Witness Thorpe further testified that the proposed line would pass directly over two planned lots for his development, and that his development would have 20 to 21 lots.

Witness Bauen testified that he resided in Andrews, North Carolina, and owned approximately 450 acres, containing his residence and two other residences, and that the property was used for farming. Witness Bauen testified that his primary concern with the proposed route related to the possible health effects of the transmission line being close to his residence. Witness Bauen was also concerned with the economic damage the proposed line would inflict on his property. Witness Bauen testified that the proposed line would be approximately 1,600 feet from a residence that he proposed to build in the future on his farm. Witness Bauen testified that he did not have an actual proposed route to offer as an alternative to the route being proposed by Nantahala in this proceeding. Witness Bauen did however suggest that an alternative route be developed utilizing U. S. Forest Service land to the north of the proposed route.

The evidence presented by Nantahala in the form of testimony of witnesses Hollifield and Miller and in the Siting Study overwhelmingly supports the location of the route as proposed by Nantahala in its Application. Witness Hollifield testified that the interconnected route segments were developed through relatively low constraint areas. Although U. S. Forest Service lands carried a relatively high constraint, other areas such as residences, schools, hospitals and churches carried as high or a higher constraint than did the Forest Service land. Further, no party to this proceeding opposing the proposed route presented an alternative location for the proposed transmission line, or offered any proof to sustain its position. As required by G. S. § 62-105(a), the only evidence in the record with respect to the proposed route is that presented by Nantahala. Therefore, after careful consideration of the entire record in this proceeding, the Commission concludes that compared with reasonable alternative courses of action, construction of the transmission line in the proposed location is reasonable, preferred, and in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is found in the testimony of Company witnesses Hollifield, Siler, Olmsted, Brockington, Parker and Intervenor witnesses Thorpe and Bauen.

Company witnesses Hollifield, Siler, Olmsted, and Brockington testified with respect to measures that would be taken by Nantahala during construction to insure compliance with applicable environmental protection regulations. Witness Olmsted testified with respect to Sections 4.2, 4.3.2, 4.3.3, 5.2, 5.3.2, and 5.3.3 of the Siting Study with respect to water quality, discharge, suspended sediments, aquatic insects, and fish in the streams crossed by the proposed transmission line route. Witness Olmsted testified that he reviewed the clearing plans in regard to the protection of water quality and aquatic resources, and that if the line were built in the proposed corridor, and in compliance with the clearing and construction practices outlined in the Siting Study, that there would be no negative impact to the aquatic resources.

Witness Siler sponsored Sections 3.8.1, 3.8.2, 3.8.3, 3.8.4, 4.3.1, 5.3.I, and 5.3.4 of the Siting Study and sponsored studies by L. L. Gaddy on rare and endangered plant and animal habitats of the proposed line. Witness Siler also inspected streams to inspect their quality and susceptibility to sedimentation and reviewed potential access routes and assessed the potential environmental impact of road and tower construction. Based on his experience with performing environmental audits of approximately 50 miles of similar line construction activities in the mountains of South Carolina and North Carolina, witness Siler found that there would be no measurable effect on the natural resources in the area. Witness Siler also found no federal or state threatened or endangered plant or animal species along the proposed route, and no habitat for threatened or endangered species was found.

Witness Hollifield testified with respect to the manner in which the proposed line would cross Gipp Creek, which has been classified as an Outstanding Water Resource. Witness Hollifield testified that the line would cross Gipp Creek at a relatively narrow point in the valley, and that towers would be positioned on ridges on each side of the valley, thus allowing a single, high span across the creek. Except for minor clearing at the tower location, no trees would be cut in the Gipp Creek Watershed due to the height of the conductors above them, which he estimated to be approximately 300 feet above the floor of the creek. In addition, witness Hollifield testified that transmission towers would be constructed of darkened galvanized steel which would blend into the landscape, that the towers would utilize a lattice framework to minimize structural mass to blend with the texture of surrounding woodland areas, that conductor wires would be non-specular, having greatly reduced sheen and visibility, that helicopter construction techniques would be used in wire stringing operations to avoid land disturbance, that vegetation would be left in place, and that trees below the minimum height under the lines would be maintained to maximize watershed protection and to reduce visibility of the line.

Witness Brockington testified that it was unlikely that significant archaeological sites would be impacted by the proposed line. Witness Brockington testified that Nantahala had undertaken every possible measure to limit impact on archaeological sites, and that appropriate planning was in place to recognize any impact to sites that were not currently known.

Intervenor witnesses Thorpe and Bauen offered no specific direct testimony to counter testimony presented by the Nantahala witnesses with respect to the environmental consequences of the proposed action. However, witnesses Thorpe and Bauen testified that Nantahala's study did not take into account the nature of the state of knowledge today with respect to the health hazards of electromagnetic fields ("EMF's"). Witness Thorpe further testified that as a result of health concerns with respect to property that would be directly beneath the proposed line he would not feel safe selling lots to residences that would be within 1,000 feet of the proposed line, and that at least two of his proposed lots for his development would be within 1,000 feet of the proposed line. Intervenor witness Bauen also expressed health concerns with respect to the proposed line.

Section 5.9.5 of the Siting Study, Hollifield Exhibit No. 1, discusses the impact of electric and magnetic fields associated with the proposed line. The Siting Study concludes that studies with respect to electromagnetic fields are inconclusive, and that the EMF level (milligauss) at the edge of the right-of-way of the proposed line would likely be lower than levels simply found in homes and work places. The Siting Study therefore concludes that based on current understanding of EMF, no adverse impact is anticipated as a result of the construction of the proposed line.

Nantahala presented the rebuttal testimony of Henry Parker, employed by Duke Power Company as an engineer with a specialty in electromagnetic fields. Witness Parker testified that he, along with representatives of Carolina Power & Light Company, had testified before the Non-ionizing Committee of the North Carolina Radiation Protection Commission in December, 1991, concerning a study that had been conducted with respect to electromagnetic fields. Witness Parker testified that based on his report and study, the North Carolina Radiation Protection Commission had declined to establish guidelines with respect to electromagnetic fields. Witness Parker further testified that a gauss meter was used to measure magnetic fields, that a reading taken directly beneath a 161 KV line similar to the one being proposed by Nantahala in this proceeding produced a reading somewhere in the neighborhood of 8 milligauss. He testified that a reading of 2 milligauss would be expected at the edge of the right-of-way beneath a 161 KV line, and that the State of Florida had established a guideline of 160 milligauss at the edge of the right-of-way for a 230 KV and below line, and 200 milligauss for a 525 KV line. Witness Parker testified that these readings were standards that lines could not exceed and emphasized that the line that Nantahala proposed to construct would produce readings of 8 milligauss directly below the line. By way of comparison, witness Parker had a gaussmeter with him at the hearing, and testified that the clock in the hearing room produced a reading of 30 milligauss, and that normal household appliances produced readings anywhere from 50 to 100 milligauss. Witness Parker testified that if there were no houses or buildings at a range of 1,000 feet from a 161 KV line, the reading would be essentially 0 milligauss. Witness Parker further testified that electromagnetic fields are created by currents flowing through lines as well as currents flowing through water pipes, and that in his opinion, as an expert in the field, based on current understanding of EMF, the proposed line would have no adverse impact on the environment or on the public.

It is clear that Nantahala has attempted to place the line to avoid proximity to residences. In fact, as Nantahala witness Tucker testified, a transmission line which lowers the amount of current necessary to supply the same load actually would reduce EMF from conditions along the existing 34 KV line, and the net effect of the proposed line would be a reduction in levels of magnetic fields on the whole corridor from that existing currently. With respect to proximity to residences, the record demonstrates that the proposed line would be approximately 250 feet from the residence of Dr. Priebe. The line is across the driveway of Dr. Priebe, and would be sufficiently high to allow the retention of most trees. With respect to witness Bauen, the line as proposed by Nantahala would be approximately 1,600 feet from the proposed residence of Mr. Bauen. With regard to Intervenor witness Thorpe, there are currently no residences in his proposed development. Nantahala witness Parker testified with familiarity with respect to numerous studies cited by Intervenor Thorpe on the health effect of electromagnetic fields and concluded that the studies are inconsistent and inconclusive with respect to a correlation between health concerns and electromagnetic fields. Accordingly, upon careful consideration of all of the evidence on this issue, the Commission concludes that there would be no adverse impact on the environment or the health of individuals with respect to the proposed line.

Based on the comprehensive environmental analysis performed by Nantahala, as contained in the Siting Study, the Commission is of the opinion, and so finds and concludes, that no significant, long-term environmental impact will occur as a result of the proposed action, that no deterioration of the environment surrounding the project will result, and further that the impact of the proposed transmission line will have on the environment is justified, considering the state of the available technology and the nature and economics of the various alternatives.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the testimony of Company witness Tucker.

No party offered direct testimony contesting the Company's estimate of the proposed line in the amount of $6.9 million. Therefore, in the absence of any direct testimony to the contrary, the Commission concludes that the costs associated with the proposed transmission line is reasonable.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is found in the Transmission Facility Siting and Environmental Report, introduced as Hollifield Exhibit No. 1, and is not controverted.

FURTHER CONCLUSIONS

After carefully considering Nantahala's application and Certificate Application Report, the Commission finds and concludes that the application is in full and complete compliance with G. S. § 62-102. Proper notice was provided to all parties designated by G. S. § 62-102, and the Commission finds good cause to issue a certificate of environmental compatibility and public convenience and necessity for the construction of approximately 17 miles of new 161 KV transmission line from the Nantahala Hydro Plant to a new substation to be located near the community of Marble in Cherokee County. Pursuant to G. S. § 62-105, the Commission specifically finds and concludes as follows:

1. The proposed transmission line is necessary to satisfy the reasonable needs of the public for an adequate and reliable supply of electric energy;

2. When compared with reasonable alternative courses of action, construction of the transmission line in the location proposed by Nantahala is reasonable, preferred, and in the public interest;

3. The costs associated with the proposed transmission line of approximately $6.9 million are reasonable;

4. The impact the proposed transmission line will have on the environment is justified considering the state of available technology, the nature and economics of the various alternatives, and other material considerations; and

5. The environmental compatibility and public convenience and necessity require the transmission line.

IT IS, THEREFORE, ORDERED that a Certificate of Environmental Compatibility and Public Convenience and Necessity, which is attached hereto as Appendix A, should be and the same is hereby issued.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-13, SUB 155
Know All Men By These Presents That

NANTAHALA POWER AND LIGHT COMPANY

is hereby issued this

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND
PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO G. S. § 62-102

to construct a 161 KV transmission line approximately 17 miles in length in order to establish a strong transmission source in the area and to replace the existing long distribution radial source in order to significantly improve the continuity of service and also allow to improve the quality of service in the area and to provide adequate facilities to meet the future electrical growth in the area

to be located

in Macon County at the Nantahala Hydro Plant and continuing into Cherokee County near the community of Marble, North Carolina

subject to receipt of all federal and state permits as required by existing and future regulations prior to beginning construction; and subject to all other orders, rules, regulations and conditions as are now or may hereafter be lawfully made by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. E-2, SUB 644

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Power & Light Company for Authority to Adjust Its Electric Rates and Charges Pursuant to G.S. 62-133.2 and NCUC Rule R8-55	ORDER APPROVING A NET FUEL CHARGE DECREASE

HEARD: Friday, August 27, 1993, at 10:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William W. Redman, Jr., Presiding; Chairman John E. Thomas, and Commissioners Charles H. Hughes, Laurence A. Cobb, Allyson K. Duncan, Ralph A. Hunt, and Judy Hunt

APPEARANCES:

For the Applicant:

Len S. Anthony, Associate General Counsel, Carolina Power & Light Company, Post Office Box 1551, Raleigh, North Carolina 27602-1551

William D. Johnson, Associate General Counsel, Carolina Power & Light Company, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Public Staff:

James D. Little and Paul Lassiter, Staff Attorneys, Public Staff, North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Jo Anne Sanford, Special Deputy Attorney General and Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629
For: The Using and Consuming Public

For the Carolina Industrial Group for Fair Utility Rates (CIGFUR-II):

Ralph McDonald, Attorney at Law, Bailey & Dixon, Post Office Box 1351, Raleigh, North Carolina 27602-1351

For the Carolina Utility Customers Association, Inc. (CUCA):

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon, & Ervin, P.A., One Northsquare, Post Office Drawer 1269, Morganton, North Carolina 28680-1269

BY THE COMMISSION: Rule R8-55 of the North Carolina Utilities Commission's (Commission) Rules of Practice and Procedure and G.S. 62-133.2 require the

Commission to conduct annual public hearings in order to review changes in Carolina Power & Light Company's (CP&L or Company) cost of fuel and the fuel component of purchased power. Such hearings are to be held on the first Tuesday of August of each year. Rule R8-55 requires CP&L to file a variety of information regarding its fuel cost and fuel component of purchased power in the form of testimony and exhibits at least sixty days prior to each such annual hearing. As a result, for the 1993 hearing, CP&L was required to file its testimony and exhibits on June 4, 1993, and the hearing would normally have been held on August 3, 1993. On May 28, 1993, CP&L asked the Commission for a two-week extension, until June 18, 1993, to file its direct case. No intervening party opposed the extension and on June 2, 1993, the Commission granted CP&L's request.

On June 7, 1993, the Carolina Industrial Group for Fair Utility Rates (CIGFUR-II) filed a petition to intervene. The petition was granted by the Commission on June 9, 1993. The intervention of the Public Staff is noted pursuant to NCUC Rule R1-19(e). The Commission notes the appearance of the Attorney General in this proceeding pursuant to G.S. 62-20.

On June 15, 1993, CP&L filed a Motion for an Additional Extension of Time to file its direct testimony and exhibits. CP&L asked for an extension until July 2, 1993, which was granted by the Commission on June 18, 1993.

On June 21, 1993, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene in the proceeding. The Commission granted CUCA's petition on June 24, 1993.

On June 30, 1993, CP&L filed a motion to further delay the filing of its testimony, to delay the hearing date and to publish the required notice of change in date of hearing to its customers. Specifically, CP&L requested an extension of time to file its testimony and exhibits until July 27, 1993, and a continuance of the hearing until August 27, 1993. CP&L requested permission to publish notice of the hearing to its customers as required by Rule R8-55(f). The reason CP&L requested the extensions was to finalize settlement negotiations with the parties of record. On July 2, 1993, the Commission issued its Order Scheduling Hearing, Extending the Time for Filing Testimony and Requiring Public Notice.

On July 21, 1993, CP&L and the Public Staff made an oral motion for a two-day extension of the July 27 deadline to file testimony and exhibits. On July 22, 1993, the Commission granted the request and ordered CP&L to amend the Public Notice to show the corrected filing date.

On July 29, 1993, CP&L filed its Application for a change in rates based solely on the cost of fuel in accordance with the provisions of G.S. 62-133.2 and Commission Rule R8-55 along with the testimony and exhibits of Company witnesses Roland M. Parsons and David R. Nevil. In its Application, CP&L proposed an increment of 0.033¢/kWh (0.034¢/kWh including gross receipts tax) to the base factor of 1.276¢/kWh approved in CP&L's last general rate case, Docket No. E-2, Sub 537, resulting in a proposed fuel factor of 1.309¢/kWh. The fuel factor recommended by the Company of 1.309¢/kWh was based on the adjusted historical 12-month test period ending March 31, 1993, and normalization of nuclear generation. In its Application, the Company also requested an increment of 0.020¢/kWh (0.021¢/kWh including gross receipts tax) for the Experience Modification Factor (EMF) to collect approximately $5.7 million of unrecovered fuel revenues experienced during the period April 1, 1992 to March 31, 1993. The Company proposed that the EMF rider be in effect for a fixed 12-month period. The net effect of the changes recommended by the Company results in a decrease of 2¢/1,000 kWhs usage per month. Included in the testimony and exhibits of Company witness Nevil was a Joint Stipulation of Carolina Power & Light Company, the Public Staff of the North Carolina Utilities Commission, the Attorney General of the State of North Carolina, and Carolina Industrial Group for Fair Utility Rates II that settled between these parties all issues, events and circumstances regarding operation of the Brunswick plant, recovery of unrecovered fuel expense and establishment of a fuel factor for the next year[1].

Also on July 29, 1993, the Public Staff filed with the Commission its Brunswick Investigation Report.

On August 25, 1993, the Company filed the affidavits of publication showing that public notice had been given as required by Rule R8-55(f) and the Commission's Order.

The case-in-chief came on for hearing as ordered on August 27, 1993, at 10:00 a.m. At the beginning of the hearing, the Public Staff advised the Commission of the Stipulation reached between CP&L, the Public Staff, the Attorney General and CIGFUR-II. CUCA advised the Commission that although it had not signed the Stipulation, it would waive its right of cross-examination and would not present any witnesses provided the Public Staff's Brunswick Investigation Report was admitted into the record. The Attorney General and CIGFUR-II affirmed their agreement with the Stipulation and the provisions contained within. CP&L presented the testimony and exhibits of Roland M. Parsons, Manager-Nuclear Performance Analysis and David R. Nevil, Manager-Rates & Energy Services Department. The Staff offered its Brunswick Investigation Report as part of the record in this proceeding and advised the Commission that Public Staff witnesses Dennis Nightingale, Tom Lam, Kerry Powell, Mike Maness, Kirk Kibler, and David Drooz were available to answer any questions the Commission might have regarding the report.

The Commission received into evidence the written testimony and exhibits of CP&L witnesses Parsons and Nevil and the Brunswick Investigation Report filed by the Public Staff. Based on the Joint Stipulation and CUCA's waiver of cross-examination, the Commission excused all witnesses from direct and cross examination.

CP&L was instructed to file a proposed Order with the Commission on or before September 1, 1993. All other parties were provided an opportunity to comment on CP&L's proposed Order on or before September 8, 1993.

Based upon the Company's verified Application, the testimony, and exhibits received into evidence at the hearing and the record as a whole, the Commission now makes the following:

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[1]The Joint Stipulation, as corrected at the hearing, is incorporated by reference into this Order. At the hearing, the parties agreed to correct a typographical error in the Joint Stipulation: the phrase "$1.309/kWh" on page 5 should read "1.309¢/kWh." A corrected copy is attached hereto and identified as Attachment 1.

FINDINGS OF FACT

1. Carolina Power & Light Company is duly organized as a public utility company under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. CP&L is engaged in the business of generating, transmitting, and selling electric power to the public of North Carolina. CP&L is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12-month period ended March 31, 1993.

3. CP&L's fuel procurement and power purchasing practices were reasonable and prudent during the test period.

4. The test period per book system sales are 43,774,956,724 kWhs with North Carolina Retail kWhs sales totaling 27,429,114,874 kWhs.

5. The test period per book system generation resource is 47,423,786 mWhs and is broken down by type as follows:

	mWh
Purchase - Cogeneration	3,301,648
Purchase - American Electric Power (AEP)	2,089,136
Purchase - Southeastern Power Authority (SEPA)	209,895
Purchase - Other	1,738,692
Hydro	1,008,445
Coal	28,975,326
IC	61,860
Nuclear	10,215,991
Off-System Sales	(177,207)
TOTAL	47,423,786

6. The adjusted test period system sales of 44,093,158,370 kWhs results from adjustments to per book sales of a positive 1,128,272,874 kWhs for customer growth, a positive 167,776,114 kWhs associated with weather normalization and a negative 977,847,342 kWhs associated with normalization of SEPA and North Carolina Eastern Municipal Power Agency (Power Agency or NCEMPA) transactions.

7. The adjusted test period system generation which is appropriate for use in this proceeding is 48,777,712 mWhs.

8. The appropriate fuel prices for use in this proceeding are as follows:

A. The coal fuel price is $17.07/mWh.
B. The IC turbine fuel price is $111.42/mWh.
C. The nuclear fuel price is $4.86/mWh.
D. The fuel price for AEP purchase is $10.68/mWh.
E. The fuel price for other purchases is $16.82/mWh.
F. The fuel price for off-system sales is $15.33/mWh.

9. The system normalized nuclear capacity factor which is appropriate for use in this proceeding for billing purposes is 64.48%.

10. The adjusted test period fuel expense which is appropriate for use in this proceeding is $577,165,638.

11. The proper fuel factor for this proceeding is 1.309¢/kWh, excluding gross receipts tax.

12. The Company's North Carolina test period jurisdictional fuel expense undercollection is $31,165,232.

13. The appropriate amount of undercollection to recover in this proceeding is $5,665,232.

14. The Company's Experience Modification Factor (EMF) is an increment of .020¢/kWh (including gross receipts tax the factor is .021¢/kWh). The adjusted North Carolina jurisdictional test year sales are 28,100,914,572 kWh.

15. The Company's operation of its base load fossil plants was reasonable and prudent during the test period. The Company did not meet the level of operation of its nuclear units described by Commission Rule R8-55.

16. The $5,665,232 undercollection of fuel expense to be collected by the Company through the EMF will be subject to refund with interest to CP&L's North Carolina retail customers if the Brunswick Plant fails to achieve a three-year average capacity factor of 63.88% for operations within CP&L's control during the period April 1, 1993 through March 31, 1996. The refund will be pro-rated based on the level of performance below 63.88% and above 57.39%.

17. CP&L may be required to refund to its North Carolina retail customers up to an additional $10 million if the Brunswick Plant fails to achieve a three-year average capacity factor of 57.39% for operations within CP&L's control during the period April 1, 1993 through March 31, 1996. The refund will be based on $20,000 for each one-hundredth of a percentage point below 57.39% with a maximum refund of $10 million.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence for Finding of Fact No. 1 is essentially informational, procedural, and jurisdictional in nature and is not controversial.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2 sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for a historical 12-month period. In NCUC Rule R8-55(b), the Commission has prescribed the 12 months ending March 31 as the test period for CP&L. All prefiled exhibits and testimony submitted by the Company in support of its Application utilized the 12 months ended March 31, 1993, as the test year for purposes of this proceeding.

The test period proposed by the Company was not challenged by any party and the Commission concludes that the test period which is appropriate for use in this proceeding is the 12 months ended March 31, 1993, adjusted for weather normalization, customer growth, generation mix, and normalization of SEPA and NCEMPA transactions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding can be found in the Company's Application and the monthly fuel reports on file with this Commission. Commission Rule R8-52(b) requires each utility to file a Fuel Procurement Practice Report at least once every 10 years, as well as each time the utility's fuel procurement practices change. In its Application, the Company indicated that the procedures relevant to the Company's procurement of fossil and nuclear fuels were filed in the Fuel Procurement Practices Report dated February 1987 filed in Docket No. E-100, Sub 47. In addition, the Company files monthly reports as to the Company's fuel costs pursuant to Rule R8-52(a) under its present procurement practices. No party offered any testimony contesting the Company's fuel procurement and power purchasing practices.

The Commission concludes that CP&L's fuel procurement and power purchasing practices and procedures were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for Finding of Fact No. 4 can be found in the exhibits of Company witness Nevil. The Company has reported in its monthly fuel reports to the Commission that system meter level sales were 43,774,956,724 Kwhs for the test period and North Carolina retail sales totaled 27,429,114,874 Kwhs. This level of sales was not challenged by any party and was used as the basis for the test period adjustments.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding can be found in the workpapers of Company witness Nevil. The per books total system generation value of 47,423,786 mWhs (including Power Agency ownership) reflects the generation resources available to serve CP&L's customers. This generation level was not challenged by any other party.

The test period per book generation is broken down by type as follows:

	mWh
Purchase - Cogeneration	3,301,648
Purchase - (AEP)	2,089,136
Purchase - (SEPA)	209,895
Purchase - Other	1,738,692
Hydro	1,008,445
Coal	28,975,326
IC	61,860
Nuclear	10,215,991
Off-System Sales	(177,207)
TOTAL	47,423,786

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding is contained in the testimony and exhibits of Company witness Nevil. The Company calculated kWh adjustments for customer growth, normal weather, SEPA normalization, and Power Agency supplemental totaling a positive 318,201,646 kWhs.

The Company calculated a positive customer growth adjustment of 1,128,272,874 kWhs for the system and 660,684,782 kWhs for North Carolina retail. The method employed by the Company in making this calculation utilizes the end-of-period number of customers. This method was used by the Company and adopted by this Commission in the past four fuel cases.

The Company calculated a positive weather normalization adjustment of 167,776,114 kWhs on a system basis and 11,114,916 kWhs for North Carolina retail.

The Company calculated a positive adjustment of 22,230,710 kWhs for the normalization of kWh deliveries from the SEPA hydro project based on a 25-year history. These kWhs are delivered to CP&L's wholesale customers and Power Agency.

The Company's filing showed a negative adjustment of 1,000,078,052 kWhs for Power Agency supplemental sales based on the nuclear capacity factors used by the Company in determining a fuel factor. The Power Agency has ownership in three of the Company's nuclear units: Brunswick 1, Brunswick 2, and Harris 1. Adjustments to the ownership/supplemental kWhs for Power Agency are necessary each time the nuclear capacity factors are normalized to a level that is different from the test year actual performance. See Finding of Fact No. 9 on the normalization of nuclear generation. The Commission adopts the negative Power Agency supplemental sales adjustment of 1,000,078,052 kWhs proposed by CP&L.

The total of all the adjustments to kWh meter level sales is a positive 318,201,646 kWhs. When this adjustment is added to per book meter level kWh sales found appropriate in Finding of Fact No. 4, the result is a total adjusted kWh sales of 44,093,158,370. The Commission finds these kWh adjustments appropriate and consistent with the adjustments made in past cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding is contained in the testimony and exhibits of Company witness Nevil.

The Company applied losses to the kWh adjustments calculated for customer growth and weather normalization and determined that these adjustments total 1,353,926 mWhs at the generation level. The adjusted generation level of 48,777,712 mWhs is determined by adding the adjustments to the per book values. The Commission notes that no party took issue with the adjustments calculated by the Company and finds that the proper level of adjusted generation is 48,777,712 mWhs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Nevil.

The Company's fuel factor calculation utilized the burned fuel prices for coal, internal combustion turbines (IC), and nuclear experienced in March 1993, the last month of the test period. The prices utilized by the Company were:

Coal	17.07 $/mWh
IC	111.42 $/mWh
Nuclear	4.86 $/mWh
AEP Purchase	10.68 $/mWh
Other Purchases	16.82 $/mWh
Sales	15.33 $/mWh.

The Commission concludes that the prices for coal, IC, nuclear, purchases and sales as proposed by CP&L are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9, 10 & 11

The evidence supporting these findings is contained in the testimony and exhibits of Company witness Nevil.

In Nevil Exhibit No. 3, the Company normalized the capacity factors for its nuclear units in accordance with Commission Rule R8-55(c)(1) by using the five-year North American Electric Reliability Council (NERC) Equipment Availability Report 1989-1992 average for boiling water reactors (BWRs) and pressurized water reactors (PWRs). The capacity factors of Brunswick Unit Nos. 1 and 2, both BWRs, were normalized at 58.93% and the capacity factors of the Robinson and Harris Units, both PWRs, were normalized at 69.96%. The Company's normalization calculations resulted in a system nuclear capacity factor of 64.48% and produces a fuel factor of 1.309¢/kWh based on a system fuel expense of $577,165,638 and normalized meter sales of 44,093,158 mWhs. The methodology used by the Company to normalize its nuclear capacity factors and to compute its fuel expense in this proceeding is the same methodology employed by both the Company and Public Staff in past fuel cases. In the Joint Stipulation between CP&L, the Public Staff, Attorney General and CIGFUR-II, these parties agreed to a fuel factor of 1.309¢/kWh calculated as described above. Therefore, the Commission finds good reason to approve the fuel factor agreed to in the Joint Stipulation. The Commission concludes that the appropriate capacity factors to use in this proceeding are 58.93% for BWRs and 69.96% for PWRs which result in a system nuclear capacity factor of 64.48%.

Based on the evidence of record, the Commission concludes that a fuel factor of 1.309¢/kWh using a 64.48% nuclear capacity factor and March burned fuel costs for coal and IC turbines is just and reasonable and should be approved. This factor is 0.033¢/kWh higher than the base fuel factor of 1.276¢/kWh approved in CP&L's last general rate case, Docket No. E-2, Sub 537. The calculation of the 1.309¢/kWh fuel factor is shown in the following table:

	mWh Gen	$/mWh	Fuel Cost
Coal	24,077,784	17.07	$411,007,773
Nuclear	17,308,080	4.86	84,117,269
IC	51,404	111.42	5,727,434
Hydro	724,980	-	-
Purchases: Co-Gen	3,301,648	-	60,591,940
AEP	1,833,400	10.68	19,580,712
SEPA	182,861	-	-
Other	1,444,810	16.82	24,301,704
Sales	(147,255)	15.33	(2,257,419)
Total Adjusted	**48,777,712**		**$603,069,413**
NCEMPA Adjustments:			
Nuclear Ownership			(11,136,583)
Coal Ownership			(18,230,401)
Harris Buyback			2,070,946
Mayo Buyback			1,392,263
Net Fuel Cost			**$577,165,638**
kWh for Fuel Factor			44,093,158,370
Fuel Factor (¢/kWh)			1.309

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 & 13

The evidence supporting these findings is contained in the testimony and exhibits of Company witness Nevil and the Public Staff Brunswick Investigation Report.

Company witness Nevil testified that CP&L underrecovered its fuel expense by $31,165,232 during the test period. Witness Nevil testified that pursuant to the terms and conditions of the Joint Stipulation, the Company was seeking to recover $5,665,232 of the underrecovery through an EMF factor to be effective for a 12-month period and that CP&L would agree to forego the recovery of the balance of the underrecovery.

For the reasons set forth in Findings of Fact Nos. 15-17 and based on the testimony and exhibits of witness Nevil and the Joint Stipulation, the Commission concludes that CP&L is entitled to recover $5,665,232 of the amount actually underrecovered during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding can be found in the direct testimony and exhibits of Company witness Nevil.

Pursuant to the terms and conditions of the Joint Stipulation, the Company proposed an EMF increment factor of 0.020¢/kWh (0.021¢/kWh with gross receipts tax) to recover $5,665,232 of unrecovered fuel expense. This EMF increment factor was determined by dividing the unrecovered amount by North Carolina retail adjusted kWhs of 28,100,914,572. CP&L asked that this factor remain in rates for a 12-month period.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced overrecovery or underrecovery of reasonable fuel expenses prudently incurred during the test period...in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the overrecovery or underrecovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case..."

For the reasons set forth in Findings of Fact Nos. 15-17 and based on the testimony and exhibits of CP&L witness Nevil and the provisions of the Joint Stipulation, the Commission concludes that the EMF increment of 0.020¢/kWh (0.021 ¢/kWh with gross receipts) is appropriate for use in this proceeding. The EMF increment shall remain in effect for a fixed 12-month period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15, 16, & 17

The evidence for these findings can be found in the Company's Application, testimony of CP&L witnesses Nevil and Parsons, and the Brunswick Investigation Report filed and supported by the Public Staff.

The Company files with this Commission monthly Fuel Reports and Base Load Power Plant Performance Reports. These reports were filed in Docket No. E-2, Sub 618 for calendar year 1992 and Docket No. E-2, Sub 639 for calendar year 1993. Information obtained from these reports indicates that CP&L's test period nuclear capacity factor of 38.06% and two-year average capacity factor of 57.63% are below the most recent NERC 5-year average capacity factor level of 64.48% described in NCUC Rule R8-55(i).

Witness Parsons testified that the CP&L fossil system achieved an equivalent availability factor of 86.1% during the test period compared to the NERC five-year average of 81.7%. The Company's four base load fossil units each had availabilities in excess of 80%. Based on the evidence presented by the Company and the Public Staff, the Commission concludes that the operation of the Company's base load fossil plants during the test period was reasonable and prudent.

Witness Parsons described the operation of CP&L's nuclear units during the test period. Parsons testified that Robinson Unit 2 and Harris performed extremely well, achieving capacity factors of 68.9% and 74.2%, respectively, even though <u>both</u> units experienced refueling outages during the test period. Witness Parsons discussed at length the outage experienced by the Brunswick Plant that began on April 21, 1992 and extended through the end of the test period. Witness Parsons explained the cause of the outage and the corrective actions taken by the Company during this outage. Witness Parsons stated that the discovery of improperly installed anchor bolts in the diesel generator building caused concern with the structural integrity of the building's walls and thus made the diesel generators inoperable and forced the plant into an outage. Once the outage was underway and corrective work was being performed in the diesel generator building, issues were raised regarding the structural integrity of other bolts throughout the plant. This broader investigation of bolts and other items throughout the plant greatly increased the scope of investigations and corrective work and thus increased the duration of the outage. The investigation process was not limited to anchor bolts but expanded to include wall construction and the adequacy of miscellaneous structural steel. Parsons testified that the Company had to expend many days of manpower to evaluate the numerous systems throughout the plant to verify their structural integrity. The time required to inspect and analyze the plant components was as follows: drilled in anchors in concrete, 269 days; drilled in anchors in masonry walls, 290 days; masonry wall evaluation program, 279 days; and miscellaneous steel verification program, 293 days.

Parsons testified that the Company made good use of this outage to accomplish necessary maintenance work and plant enhancements. As of mid-May 1993, the Company had completed 31,000 of 41,000 identified work items. Several of the corrective procedures performed during the outage could only be performed with both units out of service. This work, as well as other inspection/correction procedures performed, will avoid the need for future plant outage time.

During the summer of 1992, the Public Staff began an audit of the Brunswick Plant. The final result of the Staff's audit entitled Brunswick Investigation Report was filed on July 29, 1993, and was made a part of the record in this proceeding. The Staff's report reviewed CP&L's management, plant improvement programs, outage management, maintenance and plant equipment. The Public Staff's audit indicates that a portion of the Brunswick outage may have been the result of CP&L management imprudence.

As a result of the Brunswick outage, the Company's nuclear units failed to meet the one- and two-year operational standards described in Commission Rule R8-55(i) which, according to the Rule, creates a rebuttable presumption that the increased fuel expense resulting therefrom was imprudently incurred. The testimony presented by CP&L and the Public Staff's report indicate strong disagreement between the parties regarding the prudence or imprudence of the Brunswick Plant outage. Both parties could present substantial evidence in support of their respective positions. It would be very difficult to determine which portion or portions of the outage, if any, were the result of CP&L's management imprudence and, in turn, what fuel expense resulted from imprudence. In recognition of this fact and the complexity of this matter, these two parties, the Attorney General and CIGFUR-II resolved these issues through lengthy negotiations and entered into the Joint Stipulation. Pursuant to the Joint Stipulation, CP&L has agreed to forego recovery of $25.5 million of its test year underrecovery and has agreed to certain additional performance standards for the Brunswick Plant over the three-year period beginning April 1, 1993, and ending March 31, 1996. If the combined operation of the Brunswick Plant does not meet the additional performance standards outlined in the Joint Stipulation, CP&L will be required to refund up to $15.7 million plus interest to its North Carolina retail customers as follows:

(A) If the Brunswick Plant capacity factor for the three-year period is below 63.88% but greater than 57.39%, CP&L shall refund to the North Carolina retail customers a pro-rata portion of the $5,665,232 EMF (with interest at 10%) recovered in this Docket. The refund will be pro-rated based on the level of performance below 63.88% and above 57.39%;

(B) If the Brunswick Plant capacity factor for the three-year period is below 57.39%, the Company shall also refund to its North Carolina retail customers $20,000 for each one-hundredth of a percentage point below 57.39% with a maximum refund of $10 million, and this amount is over and above the $5,665,232 refund plus interest for not exceeding the 57.39% performance level.

If the plant's average capacity factor for the three-year period is equal to or in excess of 63.88%, CP&L will not be required to refund any additional funds to its North Carolina retail customers.

The additional performance standards apply to the extent that the performance of the plant is "within the Company's control." Outages or shutdowns at the Brunswick Plant that are beyond the control of the Company will not be considered in applying the additional performance standards. CP&L elaborated upon this point at the hearing, and the Public Staff agreed to the explanation given by CP&L.

After careful consideration of CP&L's testimony and the Public Staff's report, the Commission finds that the resolution of the issues in this proceeding as set forth in the Joint Stipulation is just and reasonable and in the public interest, that the issues should be decided as provided in the Joint Stipulation, and that the Joint Stipulation should be approved.

CUCA, the only party who did not sign the Joint Stipulation, has filed a brief raising several concerns. The Commission has considered all of the arguments and rejected them. Three arguments will be addressed here.

CUCA questions the lawfulness of the performance standards and associated refund provisions in the Joint Stipulation. The Commission has no doubt as to the lawfulness of the present Order. The Commission has not just approved the Joint Stipulation. The Commission has found the terms of the Joint Stipulation to be just and reasonable and in the public interest, and has resolved the issues in this docket consistent with the terms of the Joint Stipulation. The Commission has authority to enforce all of its orders, and we do not doubt our authority to enforce this one. Further, the parties referred to the Joint Stipulation as a contract. By the stipulation, CP&L has assumed certain obligations, including the obligation to meet additional performance standards at the Brunswick Plant and to refund monies if the standards are not met. In asking the Commission to approve the stipulation, CP&L has assumed these obligations not only to the parties, but to this Commission and to all its ratepayers.

CUCA states that the record is inadequate because it does not quantify the fuel expense resulting from imprudence "with any clarity or suggest an adequate proxy . . ." We disagree. The record includes the testimony of CP&L and the Public Staff's report, as well as the Joint Stipulation. Altogether, the evidence provides a basis for this Order. The Commission's role when faced with a settlement among some, but not all, parties to a docket is to receive the stipulation in evidence, proceed with a hearing to allow other parties an opportunity to be heard, and consider the stipulation along with all evidence presented. That is what the Commission did in this case, but CUCA presented no evidence. CUCA asserts that a further hearing should be scheduled, but at the hearing already held, CUCA presented no witnesses and waived cross examination.

CUCA says it did not have time to prepare, but it never asked for an extension. CUCA is in a poor position to request a further hearing now.

Finally, CUCA warns that the Commission's preference for settlements is "fraught with danger." The Commission notes that no less of an authority than the Chief Justice of North Carolina has spoken favorably of negotiated settlements in public utility cases. Speaking to the Southeastern Association of Regulatory Utility Commissioners in Asheville on May 27, 1990, Chief Justice Exum stated:

> The better lawyers have always recognized that their highest calling is to be peacemakers, healers, and reconcilers, to smooth over difficulties, to take up others' burdens and, as one of our greatest lawyers, John W. Davis said, "to make possible the peaceful life in a peaceful state." The last decade has seen a whole new movement in the legal profession known as alternatives to litigation. Lawyers and courts are recognizing that the adversarial process is not always the best way to resolve disputes and that some disputes are better resolved through methods like arbitration and mediation. So I think it will be for utility regulation in the future. Recent experiences in Illinois and here in North Carolina provide encouraging signs in this direction.
>
> So for the future of utility regulation I see . . . the resolution of more issues by negotiation and mediation rather than adversarial litigation.

As already indicated, the Commission has not just accepted this stipulation (or any other) at face value. The Commission had examined the stipulation and found the terms to be just and reasonable.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after September 15, 1993, CP&L shall adjust the base fuel component in its North Carolina retail rates by an amount equal to a 0.033¢/kWh increment (0.034¢/kWh including gross receipts tax) from the base fuel component approved in Docket No. E-2, Sub 537. Said increment shall remain in effect until changed by a subsequent Order of this Commission in a general rate case or fuel case.

2. That CP&L shall establish an EMF Rider as described herein to reflect an increment of 0.020¢/kWh (0.021¢/kWh including gross receipts tax). The EMF shall remain in effect for a 12-month period beginning September 15, 1993.

3. That CP&L shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein not later than five (5) working days from the date of this Order.

4. That the Joint Stipulation signed by CP&L, the Public Staff, the Attorney General and CIGFUR-II is approved by this Commission and will be in effect for a three-year period beginning April 1, 1993.

5. That CP&L shall notify its North Carolina retail customers of the fuel adjustments approved herein by including the Notice to Customers of Net Rate

Decrease attached as Appendix A as a bill insert with bills rendered during the Company's next normal billing cycle.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

For Attachment I See Official Copy of Order in Chief Clerk's Office.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. E-2, SUB 644

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Power & Light Company for Authority to Adjust Its Electric Rates and Charges Pursuant to G.S. 62-133.2 and NCUC Rule R8-55	)	NOTICE TO CUSTOMERS OF NET RATE DECREASE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order on September 14, 1993, after public hearings, approving a fuel charge decrease of approximately $562,000 in the rates and charges paid by the retail customers of Carolina Power & Light Company in North Carolina. The net rate decrease will be effective for service rendered on and after September 15, 1993. The rate decrease was ordered by the Commission after review of CP&L's fuel expense during the 12-month test period ended March 31, 1993, and represents changes experienced by the Company with respect to its reasonable cost of fuel and the fuel component of purchased power during the test period.

The Commission Order will result in a monthly net rate decrease of approximately 2¢ for a typical residential customer using 1,000 kWhs per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. E-7, SUB 517

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Power Company Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	)	ORDER APPROVING NET FUEL CHARGE RATE INCREASE

HEARD: Tuesday, May 4, 1993, at 10:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Julius A. Wright, Presiding; Commissioners Sarah Lindsay Tate and Charles H. Hughes

APPEARANCES:

For Duke Power Company:

W. Larry Porter, Associate General Counsel, Duke Power Company, 422 South Church Street, Charlotte, North Carolina 28242-0001; and Robert W. Kaylor, Bode, Call & Green, Post Office Box 6338, Raleigh, North Carolina 27628-6338

For the Public Staff:

A. W. Turner, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0510
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Karen E. Long, Assistant Attorney General, and Margaret A. Force, Associate Attorney General, Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629
For: The Using and Consuming Public

For Carolina Utility Customers Association, Inc. (CUCA):

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon, & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28655

BY THE COMMISSION: On March 5, 1993, Duke Power Company (Duke or the Company) filed an application pursuant to G.S. 62-133.2 and NCUC Rule R8-55 relating to fuel charge adjustments for electric utilities. In its application, Duke proposed a fuel factor of 1.0981¢/kWh (including nuclear fuel disposal costs and excluding gross receipts tax), which is a decrease of .0051¢/kWh from the base fuel factor of 1.1032¢/kWh set in the Company's last general rate case proceeding, Docket No. E-7, Sub 487. The Company further adjusted the proposed factor by two decrement proposals for the Experience Modification Factor (EMF) and EMF interest, these proposed factors excluding gross receipts taxes are .0972¢/kWh and .0117¢/kWh, respectively, and result in a recommended net fuel factor of .9892¢/kWh.

On March 17, 1993, the Commission issued an Order scheduling hearing, requiring public notice and establishing certain filing dates.

The Attorney General and the Carolina Utility Customers Association, Inc. (CUCA), each filed timely notices to intervene, and those interventions were allowed by the Commission. The intervention of the Public Staff is noted pursuant to NCUC Rule R1-19(e).

On April 13, 1993, the Public Staff filed the affidavit of Thomas S. Lam and on April 16, 1993, the testimony and exhibits of Michael C. Maness.

The Company has filed the affidavits of publication showing that public notice had been given as required by the Commission Order issued March 17, 1993.

The case came on for hearing as ordered on May 4, 1993. Duke presented the testimony and exhibits of Candace A. Paton, Manager, Regulatory Accounting, Rates and Regulatory Affairs Department. The Public Staff presented the testimony and exhibits of Michael C. Maness, Supervisor of the Electric Section of the Accounting Division, and by affidavit, the testimony of Thomas S. Lam, Engineer in the Electric Division. No other party presented witnesses and no public witnesses appeared at the hearing.

On May 14, 1993, Duke filed Paton Late Filed Exhibit 7.

All parties to the proceeding were provided an opportunity to file proposed orders with the Commission. Duke, the Public Staff and CUCA filed proposed orders and the Attorney General filed a brief.

Based upon the Company's verified application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission now makes the following

FINDINGS OF FACT

1. Duke Power Company is duly organized as a public utility company under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. Duke is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina. Duke is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12-months ended December 31, 1992.

3. Duke's fuel procurement and power purchasing practices were reasonable and prudent during the test period.

4. The test period per book system sales are 68,290,386 mWh.

5. The test period per book system generation is 75,631,060 mWh and is broken down by type as follows:

	mWh
Coal	28,998,538
Oil & Gas	5,221
Light Off	-
Nuclear	33,924,971
Hydro	2,191,822
Net Pumped Storage	(357,869)
Purchased Power	676,088
Interchange Purchases	339,114
Catawba Contract Purchases	9,465,743
Catawba Interconnection Agreements	354,423
Interchange	33,009
Total Generation	75,631,060

6. The system normalized nuclear capacity factor for use in this proceeding is 75% and its associated generation is 33,364,102 mWh.

7. The adjusted test period sales of 69,313,231 mWh consists of test period system sales of 68,290,386 mWh which are increased by 365,533 mWh for customer growth and 1,041,448 mWh associated with weather normalization, and reduced by 384,136 mWh associated with the adjustment for Catawba retained generation.

8. The adjusted test period system generation for use in this proceeding is 76,662,159 mWh and is broken down by type as follows:

	mWh
Coal	32,992,037
Oil & Gas	5,987
Light Off	-
Nuclear	33,364,102
Hydro	1,701,300
Net Pumped Storage	(517,165)
Purchased Power	676,088
Interchange Purchases	339,114
Catawba Contract Purchases	8,100,696
Total Generation	76,662,159

9. The appropriate fuel prices and fuel expenses for use in this proceeding are as follows:

A. The coal fuel price is $16.40/mWh.
B. The oil and gas fuel price is $102.39/mWh.
C. The appropriate Light Off fuel expense is $3,857,000.
D. The nuclear fuel price is $5.84/mWh.
E. The purchased power fuel price is $13.00/mWh.
F. The interchange fuel price is $17.92/mWh.
G. The Catawba Contract Purchase fuel price is $5.91/mWh.

10. The adjusted test period system fuel expense for use in this proceeding is $761,101,000.

11. The proper fuel factor for this proceeding is 1.0981¢/kWh, excluding gross receipts tax.

12. The Company's North Carolina test period jurisdictional fuel expense overcollection was $41,461,000. The adjusted North Carolina jurisdictional test year sales are 42,673,963 mWh.

13. The Company's Experience Modification Factor (EMF) is a decrement of .0972¢/kWh, excluding gross receipts tax.

14. Interest expenses associated with the overcollection of test period fuel revenues amount to $6,219,000, based upon a 10% annual interest rate.

15. The EMF interest decrement is .0146¢/kWh, excluding gross receipts tax.

16. The final fuel factor is 0.9863¢/kWh, excluding gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural and jurisdictional in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. In NCUC Rule R8-55(b), the Commission has prescribed the 12 months ending December 31 as the test period for Duke. The Company's filing was based on the 12 months ended December 31, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

NCUC Rule R8-52(b) requires each utility to file a Fuel Procurement Practices Report at least once every ten years, and each time the utility's fuel procurement practices change. Procedures related to Duke's procurement of fossil and nuclear fuels were filed in Docket No. E-100, Sub 47, and remained in effect throughout the 12 months ended December 31, 1992. In addition, the Company files monthly reports of its fuel costs pursuant to NCUC Rule R8-52(a).

No party offered direct testimony contesting the Company's fuel procurement and power purchasing practices. In the absence of any direct testimony to the contrary, the Commission concludes these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 - 6

The evidence for these findings of fact is found in the testimony of Company witness Paton.

Company witness Paton testified that the test period per books system sales were 68,290,386 mWh and test period per book system generation was 75,631,060 mWh. Public Staff witness Lam in his affidavit accepted these levels of test period per book system sales and generation for use in the fuel computation. Additionally, neither the Attorney General nor CUCA attempted to elicit any evidence on cross-examination to indicate any disagreement with witness Paton's testimony in this regard. The test period per book generation is broken down by type as follows:

	mWh
Coal	28,998,538
Oil & Gas	5,221
Light Off	-
Nuclear	33,924,971
Hydro	2,191,822
Net Pumped Storage	(357,869)
Purchased Power	676,088
Interchange Purchases	339,114
Catawba Contract Purchases	9,465,743
Catawba Interconnection Agreements	354,423
Interchange	33,009
Total Generation	75,631,060

Witness Paton testified that Duke achieved a system nuclear capacity factor of 78% for the test period. Witness Paton normalized the system nuclear capacity factor to a level of 75%, which is an average of the actual 78% test year performance and the 72% capacity factor used by the Commission to determine the base fuel rate in Duke's last general rate case proceeding, Docket No. E-7, Sub 487 and in the Company's last fuel adjustment proceeding, Docket No. E-7, Sub 501. The most recent (1987-1991) North American Electric Reliability Council's five-year average nuclear capacity factor for all pressurized water reactor units is 67.64%. Public Staff witness Lam supported the use of the 75% nuclear capacity factor proposed by the Company. Further, neither the Attorney General nor CUCA attempted to elicit any evidence on cross-examination to indicate any disagreement with witness Paton's testimony in this regard.

Based upon the agreement of the Company and the Public Staff as to the appropriate numbers, and noting the absence of evidence presented to the contrary, the Commission concludes that the test period level of per book sales and generation are reasonable and appropriate for use in this proceeding.

Based upon the past nuclear performance of the Duke system and national data, the Commission believes that Duke's nuclear performance during the test year should be normalized. The Commission concludes that the 75% nuclear capacity factor and its associated generation of 33,364,102 mWh, proposed by Duke and accepted by the Public Staff, is reasonable and appropriate for determining the appropriate fuel costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is found in the testimony of Company witness Paton.

Witness Paton adjusted total per book test period sales by 1,022,845 mWh. This adjustment is the sum of adjustments for customer growth, weather normalization and Catawba retained generation of 365,533 mWh, 1,041,448 mWh, and a negative 384,136 mWh, respectively. The level of Catawba retained generation is associated with the Company's normalized system nuclear capacity factor of 75%.

The Public Staff accepted witness Paton's adjustment for customer growth, weather normalization and Catawba retained generation. Additionally, neither the Attorney General nor CUCA attempted to elicit any evidence on cross-examination to indicate any disagreement with witness Paton's testimony in this regard.

The Commission concludes that the adjustments for customer growth of 365,533 mWh, weather normalization of 1,041,448 mWh, and Catawba retained generation of a negative 384,136 mWh as presented by the Company and reviewed and accepted by the Public Staff, are reasonable and appropriate for use in this proceeding. Therefore, the Commission concludes that the per book test period system sales of 68,290,386 mWh should be increased by 1,022,845 mWh resulting in an adjusted test period sales level of 69,313,231 mWh which is both reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is found in the testimony of Company witness Paton.

Witness Paton made an adjustment of 1,031,099 mWh to per book generation, for adjustments relating to weather normalization, customer growth and Catawba retained generation, based on a 75% normalized system nuclear capacity factor and, therefore, calculated an adjusted generation level of 76,662,159 mWh.

Witness Lam reviewed and accepted witness Paton's adjusted generation level of 76,662,159 mWh. Further, neither the Attorney General nor CUCA attempted to elicit any evidence on cross-examination to indicate any disagreement with witness Paton's testimony in this regard.

The Commission concludes, after finding Duke's and the Public Staff's recommended normalized system nuclear capacity factor of 75% reasonable and appropriate in Finding of Fact No. 6 and adjustments to sales for customer growth, weather normalization and Catawba retained generation reasonable and appropriate in Finding of Fact No. 7, that the Duke and Public Staff adjustment to per book system generation of 1,031,099 mWh and the resulting adjusted test period system generation level of 76,662,159 mWh are both reasonable and appropriate for use in this proceeding. Total generation is broken down by type as follows:

	mWh
Coal	32,992,037
Oil & Gas	5,987
Light Off	-
Nuclear	33,364,102
Hydro	1,701,300
Net Pumped Storage	(517,165)
Purchased Power	676,088
Interchange Purchases	339,114
Catawba Contract Purchases	8,100,696
Total Generation	76,662,159

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 - 13

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Paton.

Witness Paton's testimony recommended fuel prices as follows: (1) coal price of $16.40/mWh; (2) oil and gas price of $102.39/mWh; (3) light-off fuel expense of $3,857,000; (4) nuclear fuel price of $5.84/mWh; (5) purchased power fuel price of $13.00/mWh; (6) interchange fuel price of $17.92/mWh; and (7) Catawba Contract purchase fuel price of $5.91/mWh.

Witness Lam in his affidavit, accepted all of witness Paton's fuel expense and fuel prices. Additionally, neither the Attorney General nor CUCA attempted to elicit any evidence on cross-examination to indicate any disagreement with witness Paton's testimony in this regard.

The Commission concludes that the Company's fuel expense and fuel prices as accepted by the Public Staff are reasonable and appropriate for use in this proceeding.

Therefore, the Commission concludes that adjusted fuel test period expenses of $761,101,000 and the fuel factor of 1.0981¢/kWh, excluding gross receipts tax, are reasonable and appropriate for use in this proceeding. This approved base fuel factor is .0044¢/kWh lower than the current base fuel factor in effect of 1.1025¢/kWh, excluding gross receipts tax.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period...in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case." Further, NCUC Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

Both Company witness Paton and Public Staff witness Lam, in his affidavit, testified that during the test year Duke over-recovered $41,461,000 in fuel revenues and that the adjusted North Carolina jurisdictional test year sales are 42,673,963 mWh. Further, neither the Attorney General nor CUCA attempted to elicit any evidence on cross-examination to indicate any disagreement with witness Paton's testimony in this regard. The $41,461,000 over-recovered fuel revenue is divided by the adjusted North Carolina jurisdictional sales of 42,673,963 mWh to arrive at an EMF decrement of .0972¢/kWh, excluding gross receipts tax. The Commission concludes that there being no controversy, the EMF decrement of .0972¢/kWh, excluding gross receipts tax, is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14 AND 15

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Paton and Public Staff witness Maness. Witness Paton proposed that an 8% annual interest rate be used for purposes of calculating the EMF interest decrement to be applied to customer refunds. Witness Maness recommended use of a 10% annual interest rate. CUCA and the Attorney General concurred with the Public Staff's proposal to use an annual interest rate of 10% to calculate interest on the fuel expense overcollection in this docket.

Company witness Paton recommended that a rate of 8%, which she testified is reflective of current trends in the cost of money, be used to calculate interest on the refund of fuel overcollections approved in this proceeding. Witness Paton testified that interest rates have declined to the current levels shown below for the following items:

Bank prime rate	6.0%
One-year CD	3.0%
Five-Year Treasury Bond	4.9%
Thirty-Year Treasury Bond	6.9%

Witness Paton also testified that during the past year mortgage rates have reached 20-year lows with rates currently around 7.5% for 30-year mortgages. She stated that it is also possible to get bank credit cards with rates as low as 8.9%.

Additionally, witness Paton testified that the Company's current Allowance for Funds Used During Construction (AFUDC) rate is 8.5% pretax and 7.2% after-tax.

Witness Paton also pointed out that there is no provision for interest to be calculated on an EMF increment when Duke or another electric utility is under-recovered on its fuel costs. Also, witness Paton noted that G.S. 62-130(e) clearly gives the Commission discretion in determining the appropriate rate of interest to be applied to refunds. Further, witness Paton commented that if the range of interest rates rises, it might be appropriate to increase the interest rate accordingly within the limits set forth in G.S. 62-130(e).

Public Staff witness Maness recommended that interest on the EMF refund continue to be calculated using a rate of 10%, the rate which has been consistently used by the Commission for all fuel refunds since the 1988 implementation of Commission Rule R8-55(c)(5) requiring interest on fuel refunds, and for the vast majority of other electric utility refunds since 1981, when G.S. 62-130(e) was enacted. [The enactment of G.S. 62-130(e) provided the Commission with the discretion to determine the just and reasonable rate to be applied to utility refunds, subject to a cap of 10% per annum.]

Witness Maness set forth two basic reasons for his proposal. First, he testified that although certain interest rates have recently declined markedly, it cannot be assumed that the cost of capital of each ratepayer is as low as the rates which could be earned on a certificate of deposit or a Treasury Security; nor should it be assumed that each ratepayer can obtain loans at the prime rate. Witness Maness pointed out that many ratepayers are undoubtedly net debtors, with credit card debt, for example, at interest rates well in excess of 10%. According to witness Maness, the use of a 10% rate recognizes that the cost of capital of the Company's ratepayers is spread across a range of rates and is not simply equivalent to the rate that could be earned on certain savings vehicles. Witness Maness also testified that consideration should be given to the fact that these funds are being involuntarily withheld from the ratepayers. Second, witness Maness testified that if the Commission were to implement a policy allowing the interest rate on refunds to track some general level of interest rates in the economy, it would only be fair to track those rates when they were both high and low. However, since the Commission is prohibited by statute from requiring a rate greater than 10%, the inevitable result of such a policy would be the tracking of rates only when they were below 10%. Witness Maness noted that when the tracked rates rose above 10%, the ratepayers would be denied the benefit of tracking. Witness Maness testified that although certain interest rates are currently low, it is certainly possible, if not probable, that interest rates will again rise above 10%. For example, the bank prime rate cited by witness Paton was above 10% for 56 out of the 132 months in the 1982-1992 time frame, including as recently as the period November 1988 - January 1990.

Witness Maness also testified that the Company had proposed the use of an 8% rate in its 1992 fuel rate proceeding, for reasons very similar to those advanced in this case, and that the Commission concluded that 10% continued to be a just and reasonable rate.

With regard to the Company's AFUDC rate, witness Maness testified that a revenue requirements level of funds of 11.8% is necessary to allow the Company to attain an after-tax AFUDC rate of 7.2%. Additionally, witness Maness testified that since most business and corporate ratepayers effectively include interest on refunds in taxable income, a pre-tax interest payment to them of over 13% would be required to provide a net-of-tax benefit of 8%.

During cross-examination of witness Paton, counsel for the Public Staff asked questions regarding Public Staff Paton Cross Examination Exhibit No. 1. This exhibit consisted of a listing of credit cards in the Wednesday, April 28, 1993, edition of the Raleigh News and Observer, purported to be the "best credit card deals nationally" as of the previous day, for people who carry balances. Witness Paton agreed that only three of the cards on the list showed interest rates less than 10%. Witness Paton also agreed that the three credit cards shown that offered interest rates less than 10% had higher annual fees than those with interest rates greater than 10%.

Witness Maness testified that credit card interest rates are "in the line of prime plus six, prime plus seven".

The Commission has carefully considered the evidence presented on this matter and concludes that the just and reasonable rate to use in this case to calculate interest on the EMF refund is 10%. Since 1981, when G.S. 62-130(e) was enacted, the Commission has consistently used 10% to calculate interest on utility refunds. During that period, interest rates have moved up and down and have generally been much higher than they are today. The Commission has specified use of a 10% rate notwithstanding the general level of interest rates in the economy on the theory that 10% provides for adequate compensation to ratepayers over the long term considering the fact that a policy of tracking the general level of interest rates in the economy would lead to the denial of fair compensation to the ratepayers when those interest rates exceed the statutory cap of 10%. Accordingly, the Commission is of the opinion that an annual interest rate of 10% is just and reasonable for purposes of this proceeding.

Based upon this conclusion that the appropriate rate to be used to calculate interest on the EMF refund in this case is 10% and on the conclusion set forth elsewhere in this Order regarding the test year fuel expense overcollection, the Commission concludes that the amount of interest expense to be added to the EMF refund totals $6,219,000. Based on the conclusion elsewhere in this Order regarding adjusted North Carolina jurisdictional mWh sales, the Commission concludes that the EMF interest decrement rider should be set at .0146¢/kWh, excluding gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

Accordingly, the fuel calculation, incorporating the conclusions reached herein result in a final net fuel factor of .9863¢/kWh, excluding gross receipts tax, as shown in the following table:

	Adjusted Generation (mWh)	Fuel Price $/mWh	Fuel Dollars (000s)
Coal	32,992,037	16.40	$541,069
Oil and Gas	5,987	102.39	613
Light Off			3,857
Nuclear	33,364,102	5.84	195,010
Hydro	1,701,300		
Net Pumped Storage	(517,165)		
Purchased Power	676,088	13.00	8,789
Interchange Purchases	339,114	17.92	6,076
Catawba Contract Purchases (including NFDC)	8,100,696	5.91	47,875
TOTAL	76,662,159		$803,289
Less: Intersystem Sales	(2,717,361)		(42,188)
Line Loss	(4,631,567)		
System mWh Sales & Fuel Cost	69,313,231		$761,101
Fuel Factor ¢/kWh			1.0981¢
EMF ¢/kWh			(0.0972)
EMF Interest ¢/kWh			(0.0146)
FINAL FUEL FACTOR ¢/kWh			0.9863¢

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after July 1, 1993, Duke shall adjust the base fuel cost approved in Docket No. E-7, Sub 487, in its North Carolina retail rates by an amount equal to a 0.0051¢/kWh decrease (excluding gross receipts tax) and further that Duke shall adjust the resultant approved fuel cost by decrements of 0.0972¢/kWh and 0.0146¢/kWh for the EMF and EMF interest, respectively. The EMF and EMF interest portion are to remain in effect for a 12-month period beginning July 1, 1993.

2. That Duke shall file appropriate rate schedules and riders with the Commission in order to implement these approved fuel charge adjustments no later than 10 days from the date of this Order.

3. That Duke shall notify its North Carolina retail customers of these approved fuel adjustments by including the "Notice to Customers of Net Rate Increase" attached as Appendix A as a bill insert with bills rendered during the Company's next normal billing cycle.

ISSUED BY ORDER OF THE COMMISSION
This the 18th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

DOCKET NO. E-7, SUB 517

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of Duke Power Company Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities) NOTICE TO CUSTOMERS OF NET RATE INCREASE

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order on June 18, 1993, after public hearings, approving a fuel charge net rate increase of approximately $21,200,000 on an annual basis in the rates and charges paid by the retail customers of Duke Power Company in North Carolina. The net rate increase will be effective for service rendered on and after July 1, 1993. The rate increase was ordered by the Commission after review of Duke's fuel expense during the 12-month period ended December 31, 1992, and represents actual changes experienced by the Company with respect to its reasonable cost of fuel and the fuel component of purchased power during the test period.

The Commission's Order will result in a monthly net rate increase of approximately 50¢ for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION
This the 18th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. E-13, SUB 157
DOCKET NO. E-13, SUB 142

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Nantahala Power and Light Company for Authority to Adjust and Increase its Electric Rates and Charges
and
Application of Nantahala Power and Light Company for Annual Purchase Power Adjustment) ORDER GRANTING PARTIAL RATE INCREASE

HEARD: Tuesday, March 30, 1993, at 7:00 p.m., Superior Courtroom, Swain County Administrative Building and Courthouse, Mitchell Street, Bryson City, North Carolina

Wednesday, March 31, 1993, at 7:00 p.m., Courtroom A, Fourth Floor, Macon County Courthouse, Five West Main Street, Franklin, North Carolina

Tuesday, April 13, 1993, at 9:30 a.m., through Friday, April 16, 1993, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sarah Lindsay Tate, Presiding, Chairman William W. Redman, Jr., and Commissioners Julius A. Wright, Robert O. Wells, Charles H. Hughes, Laurence A. Cobb and Allyson K. Duncan

APPEARANCES:

For Nantahala Power and Light Company:

Edward S. Finley, Jr., Attorney at Law, Hunton and Williams, Post Office Box 109, Raleigh, North Carolina 27602

For Jackson Paper Manufacturing Company:

David H. Permar, Attorney at Law, Hatch, Little & Bunn, 327 Hillsborough Street, Raleigh, North Carolina 27608

For the Public Staff:

A. W. Turner, Jr., and Robert B. Cauthen, Jr., Staff Attorneys, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Karen E. Long, Assistant Attorney General, and Margaret A. Force and William B. Crumpler, Associate Attorneys General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

BY THE COMMISSION: On November 20, 1992, Nantahala Power and Light Company (Nantahala or the Company) filed an application with the North Carolina Utilities Commission in Docket No. E-13, Sub 157 seeking authority to adjust and increase its rates and charges for electric service to its North Carolina retail customers effective December 20, 1992. On December 9, 1992, the Commission issued an Order declaring the matter to be a general rate case, suspending the proposed rates, requiring public notice, and scheduling public hearings.

The Attorney General filed Notice of Intervention on January 12, 1993. On February 9, 1993, Jackson Paper Manufacturing Company filed a Petition to Intervene which was allowed by Order dated February 11, 1993.

Docket No. E-13, Sub 142, is an on-going docket in which the Commission revises Nantahala's purchase power recovery factor in March of each year. In its general rate case application, Nantahala asked the Commission to postpone the 1993 revision of its purchase power recovery factor until the general rate case decision is issued, so as to avoid two rate changes within a short period of time. The Commission issued an Order in Docket No. E-13, Sub 142, on March 23, 1993, providing for the current purchase power recovery factor to remain in effect until the general rate case order. The present Order is therefore being issued in both dockets.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Bryson City: Carlton Conner, Hugh Moon, Charles Dotson, Lowell Crisp, Jim Garner, Frank Young, Ron Smith, Catherine Kelly, Elizabeth Johns, Rick Conner, and Virginia Deford

Franklin: Ed Henson, Roger Bartlett, Richard Nall, J.C. Jacobs, Shirley Oenbrink, Oscar Ledford, Melvin Pete Penland, Bill Gibson, Ann Martin, Gene Robinson, Dan Moore, Gus Leach, Patti McClure, and Dan McGaft

The Company presented the testimony and exhibits of the following witnesses: E.N. Hedgepeth, President, Nantahala Power and Light Company; Earl M. Robinson, President of Weber Fick & Wilson Division of AUS Consultants - Utility Service Group; Robert M. Spann, of Charles River Associates; Kenneth C. Stonebraker, Vice President of Finance, Nantahala Power and Light Company; and N. Edward Tucker, Jr., Executive Vice President, Nantahala Power and Light Company.

The Public Staff presented the testimony and exhibits of the following witnesses: James S. McLawhorn and Benjamin R. Turner, Jr., Electric Engineers, Electric Division of the Public Staff; Gary H. Strickland, Financial Analyst, Economic Research Division of the Public Staff; and Kelly B. Dietz, Staff Accountant, Accounting Division of the Public Staff.

The Company presented the rebuttal testimony and exhibits of the following witnesses: Earl M. Robinson, Robert M. Spann, Kenneth C. Stonebraker, N. Edward Tucker, and E.N. Hedgepeth.

By Order dated April 20, 1993, the Commission scheduled a further public hearing on Wednesday, May 26, 1993, to consider the issue of expenses resulting from damage caused by the storm of March 1993 and scheduling filing of testimony for that hearing.

On May 17, 1993, the Company and the Public Staff filed a Stipulation and Motion settling all matters in controversy on storm damage expenses and asking that the hearing on May 26 be canceled. By Order dated May 20, 1993, the hearing was canceled.

Prior to and during the course of the hearings, the parties made various motions and the Commission entered various Orders, all of which are matters of record. Additionally, pursuant to Orders of the Commission or requests of the parties, also of record, certain parties were directed or permitted to submit late-filed exhibits either during or subsequent to the hearings.

Based on the foregoing, the verified application, the testimony and exhibits received into evidence at the hearing, and the proposed orders and legal briefs submitted by the parties, the Commission now makes the following

FINDINGS OF FACT

1. Nantahala Power and Light Company is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. Nantahala is a wholly-owned subsidiary of Duke Power Company.

2. Nantahala is lawfully before this Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133.

3. The test period for purposes of this general rate case is the 12-month period ended December 31, 1991, adjusted for certain known changes based upon circumstances and events occurring up to the close of the hearing.

4. Nantahala, by its application, seeks an increase in its basic rates and charges to its North Carolina retail customers of $5,066,490.

5. The overall quality of electric service provided by Nantahala is good.

6. The stipulation reached between the Company and the Public Staff related to storm damages is reasonable and should be approved.

7. Nantahala should study the economic feasibility of conducting load research sufficient to allow it to determine customer class demands at the time of the Company's summer and winter peak demands.

8. Nantahala should conduct a study to determine the appropriate portions of capacity-related and customer-related distribution plant costs in connection with the Company's next general rate case.

9. Nantahala should conduct a study to determine customer class line losses in connection with the Company's next general rate case.

10. The appropriate level of plant in service to include in rate base for this proceeding is $131,964,517.

11. The appropriate level of accumulated depreciation to include in rate base for this proceeding is $63,824,525, which is the December 31, 1992, per books balance adjusted to reflect the stipulation between the parties related to storm damage costs.

12. It is not appropriate to reduce the December 31, 1992, per books balance of accumulated depreciation by the pro forma decrease in the annual level of depreciation expense found appropriate in this case.

13. The level of materials and supplies to include in rate base for this proceeding is $2,045,942.

14. The level of cash working capital to be included in rate base for purposes of this proceeding is $2,684,430.

15. It is unnecessary to require Nantahala at this time to perform a lead lag study in future cases as a prerequisite for Nantahala to recover investor supplied funds advanced for purchased power as a component of working capital.

16. No amount representing unamortized prior period taxes and regulatory fees should be included in deferred debits.

17. The appropriate amount to include in deferred debits for unamortized Part 12 costs is $276,115.

18. The appropriate amount to include in deferred debits for unamortized clean-up costs related to vandalism is $48,523.

19. The appropriate amount to include in deferred debits for unamortized storage site clean-up costs is $210,348.

20. No amount should be included in deferred debits for the 1985 and 1986 pipeline painting costs.

21. The appropriate amount to include in deferred debits for unamortized 1992 pipeline painting costs is $354,437.

22. The appropriate amount to be included in deferred debits for unamortized rate case expense is $145,333.

23. No amount should be included in deferred debits for the 1992 labor contract negotiation costs.

24. The appropriate amount to include in deferred debits for unamortized storm damage costs is $2,934,888.

25. The total level of deferred debits to include in rate base for purposes of this proceeding is $6,993,128.

26. The appropriate level of accrued taxes to include as a deferred credit is $658,280.

27. It is inappropriate to reduce the cost of service by flowing through the gain on the sale of land which occurred in 1988.

28. The total level of deferred credits to be deducted from rate base for this proceeding is $658,280.

29. For purposes of this proceeding, the level of customer deposits to be deducted from rate base is $343,737.

30. The level of accumulated deferred income taxes to be deducted from rate base in this proceeding is $9,769,719.

31. Cost-free capital resulting from the refund order in Docket No. E-13, Subs 29 and 35, totals $515,215 and should be deducted from rate base.

32. Nantahala Power and Light Company's reasonable rate base used and useful in providing service to its North Carolina retail customers is $68,576,541, consisting of electric plant in service of $131,964,517, materials and supplies of $2,045,942, cash working capital of $2,684,430, and deferred debits of $6,993,128, reduced by accumulated depreciation of $63,824,525, deferred credits of $658,280, customer deposits of $343,737, accumulated deferred income taxes of $9,769,719, and other cost-free capital of $515,215.

33. The appropriate level of revenue associated with growth and weather is calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues and test year kWh sales.

34. The kWh adjustments related to weather normalization and customer growth for the 12-month test period through the update period ending December 31, 1992, are 1,209,032 and 13,724,236, respectively, for a total of 14,933,268 kWh. These adjustments are appropriate for use in this proceeding.

35. The basic revenue related to weather normalization and customer growth for the test year through the update period ending December 31, 1992, is $539,859.

36. The adjusted level of sales for the test year through the update period ending December 31, 1992, is 760,415,678 kWh.

37. Total basic rate schedule revenue (excluding purchased power) for the test period through the update period ending December 31, 1992, is $19,492,814.

38. The Public Staff adjustment to include the 1992 level of revenue generated by the purchase and resale of power (in excess of the 200 mW of term energy) between TVA, Duke Power, and Nantahala is inappropriate for purposes of this proceeding.

39. It is appropriate for Nantahala to place those revenues generated by the purchase and resale of power (in excess of the 200 mW of term energy) between TVA, Duke Power, and Nantahala in a deferred account for disposition in a manner to be determined in its next general rate case proceeding.

40. The appropriate level of operating revenues for Nantahala for the test year, under present rates, and after accounting and pro forma adjustments, is $23,972,903.

41. It is appropriate to amortize and include one-fifth of the cost of one round of Part 12 inspections in operating revenue deductions.

42. It is appropriate to amortize and include one-tenth of the environmental clean-up costs in operating revenue deductions.

43. It is appropriate to amortize and include one-tenth of the 1985 and 1986 pipeline painting costs in operating revenue deductions.

44. It is appropriate to amortize and include one-third of the 1992 labor contract negotiation costs in operating revenue deductions.

45. No amount relating to prior period taxes and regulatory fees should be included in operating revenue deductions in this proceeding. The Public Staff adjustment of $(140,562) is appropriate.

46. The reserve method of accounting is the appropriate way to account for the self-insurance portion of the Company's general liability insurance.

47. It is appropriate to include $48,658 in operating revenue deductions for the self-insurance portion of the Company's general liability insurance.

48. The Public Staff adjustment to remove the $25,000 estimated increase in conservation education expense is appropriate; however, such costs, if incurred, may be placed in a deferred account pending further disposition by the Commission.

49. It is appropriate to amortize and include one-third ($72,667) of Nantahala's rate case expenses in operating revenue deductions for purposes of this proceeding.

50. The appropriate annual level of amortization for storm damage costs is $326,099.

51. The total level of operation and maintenance expense (other than purchased power) under present rates appropriate for use in this proceeding is $13,140,462.

52. The level of depreciation expense appropriate for use in this proceeding is $3,813,761.

53. The reasonable level of taxes other than income taxes to include in this proceeding is $1,374,636.

54. The level of interest on customer deposits appropriate for use in this proceeding is $19,199.

55. The Public Staff adjustment to remove all charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

56. It is appropriate to reduce income tax expense by excess deferred income taxes of $11,511.

57. Based on the other findings and conclusions set forth in this Order, the appropriate level of income tax expense under present rates for use in this proceeding is $1,089,681.

58. The reasonable level of test year operating revenue deductions for Nantahala Power and Light Company (excluding purchased power) after normalization and pro forma adjustments, under present rates, is $19,437,739.

59. The proper capitalization ratios for use in this proceeding are 56.11% for common equity and 43.89% for long-term debt. The proper embedded cost rate for long-term debt for use herein is 8.04%.

60. The overall methodology utilized by Company witness Spann, which incorporated data from his study of the authorized returns on common equity of 29 energy utilities regulated by this Commission, before consideration of his specific adjustment and recommendation related to the size of Nantahala, should be accorded the greatest weight in determining the cost of common equity for purposes of this proceeding. More specifically, his analyses under that methodology when (a) interest rates were less than 10% and when (b) interest rates were less than 9.3% should be accorded the greatest weight for said purpose.

61. The FERC staff risk premium study and approach as presented by Public Staff witness Strickland should be accorded only minimal weight for purposes of this proceeding.

62. The Moody's Electric Utility Stocks and the S&P's 40 Utility Stocks historical risk premium studies presented by Company witness Spann should be accorded only minimal weight for purposes of this proceeding.

63. Company witness Spann's addition of 50 basis points to the cost of common equity determined from risk premium studies in recognition of the size of Nantahala is not appropriate for purposes of this proceeding.

64. No allowance should be made in determining the cost of common equity due to Company witness Spann's contention that because of its size Nantahala waits longer to file a general rate increase request than does a larger utility.

65. The proper cost of common equity to Nantahala for purposes of this proceeding is 12.1%.

66. The overall fair rate of return which the Company should be allowed the opportunity to earn on its rate base is 10.32%.

67. Nantahala Power and Light Company should be authorized to increase its annual level of gross revenue under present rates by $4,333,980 (excluding purchased power revenue). After giving effect to the approved increase, the annual revenue requirement for Nantahala (excluding purchased power revenue) is $28,306,883, which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found to be just and reasonable.

68. It is not appropriate for the Company to collect interest from customers on undercollections of purchased power costs.

69. It is unnecessary at this time to require Nantahala to conduct and file with the Commission a depreciation study once every five years.

70. It is unnecessary to require Nantahala to utilize the AUS theoretical reserve study to set up separate reserve accounts for recording present and future depreciation accruals and to maintain depreciation rates on an individual account basis rather than on a functional group level.

71. The distribution of the basic revenue increase to the individual customer classes in this proceeding should be as follows:

Customer Class		Increase Multiplier
Residential	-	1.29 times overall increase
Small General Service	-	0.55 times overall increase
Large General Service	-	0.7 times overall increase
Yard Lighting	-	0.0 times overall increase
Street Lighting	-	0.0 times overall increase

72. Customer growth and weather normalization adjustments to kWh sales should be used in determining customer class revenue targets.

73. Customer class revenue calculations should be rounded down where necessary to produce the overall revenue target approved herein.

74. The minimum bill provision for residential service should be $14.00 per month.

75. Nantahala should design a separate rate schedule for industrial customers based on the Standard Industrial Classification for those customers. For

purposes of this proceeding, the industrial rate schedule should initially be designed to track the Large General Service rate schedule proposed by Nantahala herein.

76. Nantahala should be authorized to revise the formula used in calculating purchased power adjustments so that all purchased power expense is excluded from base rates and included in its Rider CP.

77. The Public Staff recommendation to alter Paragraph 2(g) of the Company's service rules and regulations is inappropriate and should be rejected.

78. The rate design, rate schedules, miscellaneous charges, and terms and conditions of service proposed by the Company are reasonable and appropriate for use in this proceeding, except as specifically modified herein.

79. The purchased power recovery factor of $0.0287 per kWh (including gross receipts tax) as proposed by Nantahala for bills rendered on and after June 27, 1993, and expiring on April 25, 1994, should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact is contained in the Company's application and in the Commission's records. These findings are generally informational and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony of Company witness Hedgepeth and various public witnesses who appeared in these hearings. The only testimony indicating a problem with service quality was offered by two public witnesses addressing service reliability in the Peachtree community of Cherokee County. Witness Hedgepeth explained the steps the Company is taking to remedy this problem. The new 161 kV line from Nantahala to Andrews for which a certificate of public convenience and necessity was granted earlier this year will increase reliability in the Peachtree area. The witnesses' complaints are being addressed in a complaint proceeding, and the Commission is satisfied that appropriate steps are being taken to improve service in that portion of the service area. A careful consideration of the testimony leads the Commission to conclude that the quality of electric service being provided to retail customers in North Carolina by Nantahala is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

Nantahala and the Public Staff filed a joint stipulation with the Commission on May 17, 1993, regarding the costs arising from the blizzard of March 1993. The agreements reached in that stipulation are uncontested. Therefore, the Commission concludes that the stipulation is reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

The evidence for these findings of fact is found in the testimony and exhibits of Company witnesses Spann and Tucker and Public Staff witness Turner.

The cost-of-service study presented by witness Spann is based on the test year ended December 31, 1991. It first allocates costs to resale customers based on peak demand and energy consumption. It then allocates the remaining costs to the Company's retail customer classes. Purchased power expenses are allocated by actual billed amount to each class. The Company's production plant is allocated by a combination of demand and energy factors; 50% of the plant is allocated by customer contribution to the winter peak demand and 50% is allocated by energy. Transmission plant is allocated by class contribution to the Company's peak demand. Distribution plant costs are allocated by a combination of demand and energy factors. Witness Spann explained that, due to Nantahala's small size, it is not cost effective for it to maintain a load research program. Therefore, he used the load research data collected by Duke Power Company to develop class demands for the cost-of-service study he presented in this case.

The results of the cost study presented by witness Spann show the residential class providing a rate of return lower than the system average rate of return, whereas the general service classes provide rates of return which exceed the system average rate of return. Witness Spann explained that the cost-of-service study should be used to guide how rates should be restructured and substantial judgment should be used in rate design. The cost-of-service study should not be mechanically or rigidly followed in designing rates.

Witness Spann noted several points with respect to the cost-of-service study. First, the Company purchases a substantial portion of its capacity and energy. As such, the ratio of rate base to sales is smaller for Nantahala than for other electric utilities. Because the denominator (rate base) in the rate-of-return calculation is smaller relative to sales, small changes in class profitability lead to larger changes in the measured class rate of return than one might observe in other electric utilities. He also noted a number of issues that arise when load data from one utility are used to develop loads in another utility, but he believes the use of Duke load research data is appropriate for developing Nantahala loads. He stated that, as more experience is gained from the use of Duke load data to develop Nantahala loads, further refinements might be appropriate. For example, no adjustment was made in the study for the higher percentage of customers in the Nantahala service area (than in the Duke service area) who heat with wood and use electricity as a back-up fuel. Witness Spann suggested that, as more experience is gained using Duke load research data in the Nantahala cost-of-service studies, an adjustment for the incidence of wood heating might be appropriate.

Public Staff witness Turner made the following recommendations concerning the next cost-of-service study for Nantahala:

1. That the Company conduct a study of the economic feasibility of conducting load research either "in-house" or under contract. This load research would be used to determine Nantahala's customer class demands at the time of the system's winter and summer peak demands.

2. That the Company conduct a study of its distribution plant to determine appropriate portions related to capacity and customer costs.

3. That the Company conduct a study showing line losses by customer class.

Witness Turner testified that a major objective of the cost study is to determine cost responsibility by customer class. An essential element of this determination is customer class contribution to the Company's peak demands. The cost study in this case relied on the load research collected by Duke Power

Company based on the customers in Duke's service area. The assumption was then made that the customer class load factors during the peak demand month were the same for Nantahala's customers. If this assumption turns out not to be true, the cost study results used for ratemaking in this case could be moving in the wrong direction.

Witness Turner's first recommendation is to determine if it is reasonable and practical for Nantahala to develop load research to determine the Company's customer class demands at the time of the system summer and winter peak demands, and if that research is reasonable and practical, to conduct the load research and use the resulting data in the preparation of the Company's next cost-of-service study. He said that Nantahala should consider either preparing the load research "in-house" or contracting the work with a firm specializing in the collection and analysis of customer class loads. Witness Turner testified that a period of six months should be a reasonable period of time for the Company to determine the feasibility of conducting the load research.

Witness Turner emphasized the importance of accuracy in determining the cost of service. He pointed out that there must be significant rate of return correction over time to bring the customer classes within the plus or minus 10 percent "band of reasonableness" utilized by the Commission.

Witness Turner's second recommendation was directed toward verification of the portion of distribution plant that is customer-related. The study filed by the Company assumed that 55% of poles, towers, and fixtures; 30% of overhead conductors and devices; and 75% of underground conductors and devices were customer-related. Witness Turner contended that the accepted methods of determining the portion of customer-related distribution plant are either the minimum plant method or the zero intercept method. He recommended that the Company determine through either one of these methods the appropriateness of the customer-related portion of distribution plant assumed by the cost study.

Witness Turner's third recommendation was to verify the line losses used in the study by customer class. He said that the line loss ratio is an important factor in determining kilowatt hour generation by customer class, which is then used in allocating energy-related cost. If the factors are not correct, costs are inappropriately allocated.

On cross-examination, witness Tucker testified that the Company was willing to conduct a study of the economic feasibility of a load research program at Nantahala either directly or through a contractor. Nantahala did not agree at this point, however, that load research makes sense for Nantahala, but the Company was willing to conduct an economic feasibility study.

Witness Tucker further stated that the Company was agreeable to conducting a study of its distribution plant to determine appropriate portions related to capacity and customer costs. He also stated that Nantahala was willing to look at the line losses to determine line losses by customer class. However, Nantahala contended that its agreement to conduct the studies in connection with its next general rate case did not mean that the studies should be conducted on an ongoing basis.

Based on the foregoing evidence, the Commission concludes that Nantahala should conduct the following studies and, with the exception of the load research study, incorporate the results in its cost-of-service study filed in its next general rate case:

1. Conduct a study to determine the economic feasibility of conducting load research to determine the Company's customer class demands at the time of the system summer and winter peak demands. The Company should consider either doing "in-house" load research or have this load research collected or analyzed by a consulting firm specializing in this work. The study should be filed with the Commission and the Public Staff within six months after the date of this Order.

2. Conduct a study to determine the appropriate portions of the capacity-related and customer-related distribution plant costs in connection with the Company's next general rate case.

3. Conduct a study to determine customer class line losses in connection with the Company's next general rate case.

Jackson Paper Company did not present any witnesses in the proceeding. However, Jackson filed a legal brief pointing out that Nantahala's 1992 purchased power costs break down to 63% for demand charges and 37% for energy charges, and yet 100% of the purchased power costs were added to the energy charges of Nantahala's customers. Jackson proposed that Nantahala be required to study the feasibility of separating purchased power costs into their demand and energy components for purposes of designing rates for the large industrial customer class.

The Commission is of the opinion that such a study would be premature at the very least. Nantahala is already being required in this proceeding to conduct various studies for the purpose of enhancing its cost-of-service allocations and rate design in connection with its next general rate case. The manner in which Nantahala passes through its purchased power costs as an additional energy charge to its customers is consistent with the manner in which fuel charge adjustments are currently passed through to the customers of our other major electric utilities. There has been insufficient discussion in this proceeding of the merits of treating Nantahala's purchased power adjustments differently than the fuel charge adjustments of the other utilities. Therefore, the Commission is not persuaded that it should require the additional study proposed by Jackson Paper at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-32

The evidence supporting these findings of fact is included in the testimony and exhibits of Company witnesses Stonebraker and Tucker and Public Staff witness

Dietz. The components and levels of rate base proposed by the Company and the Public Staff representing their final positions are set forth in the schedule below:

Item	Company	Public Staff	Difference
Electric plant in service	$131,964,517	$131,964,517	$ 0
Accumulated provision for depreciation	(63,511,331)	(63,824,525)	(313,194)
Net electric plant in service	68,453,186	68,139,992	(313,194)
Materials and supplies	2,045,942	2,045,942	0
Cash working capital	2,710,316	2,682,021	(28,295)
Deferred debits	7,374,553	6,523,157	(851,396)
Deferred credits	(658,280)	(1,624,275)	(965,995)
Customer deposits	(343,737)	(343,737)	0
Accumulated deferred income taxes	(9,814,318)	(9,585,649)	228,669
Other cost-free capital	0	(515,215)	(515,215)
Total rate base	$ 69,767,662	$ 67,322,236	$(2,445,426)

As can be seen from the above schedule, the Company and the Public Staff agree on the amounts to be included in electric plant in service, materials and supplies, and customer deposits. The Commission thus concludes that the levels of electric plant in service, materials and supplies, and customer deposits appropriate for use in this proceeding are $131,964,517, $2,045,942, and $(343,737), respectively.

Accumulated Provision for Depreciation

The first area of difference between the Company and the Public Staff is the accumulated provision for depreciation. The point of contention between the parties is whether an adjustment should be made to the December 31, 1992, balance of accumulated depreciation to correspond with the pro forma adjustment to decrease the annual level of depreciation expense. (In their stipulation on storm damage costs, which the Commission has approved, Nantahala and the Public Staff have agreed to decrease the December 31, 1992, balance of accumulated provision for depreciation by $26,621.)

Ms. Dietz testified that it would not be appropriate to decrease the December 31, 1992, balance by the decrease in annual depreciation expense because the balance of accumulated depreciation will not decrease in the future below the December 31, 1992, level. Ms. Dietz further explained that a decrease in the annual level of depreciation expense will cause accumulated depreciation to grow at a slower rate, but will not cause the accumulated depreciation balance to decrease. She also stated that making such an adjustment would result in the ratepayers being denied the benefit of the depreciation they have paid in up to December 31, 1992. Ms. Dietz also compared this issue to an accumulated deferred income tax (ADIT) issue in a Carolina Power & Light Company (CP&L) general rate case (Docket No. E-2, Sub 526), in which the Commission concluded that a reduction to per books ADIT to reflect a prospective decrease in the tax rate was not appropriate.

In his rebuttal testimony, Company witness Stonebraker argued that any change in depreciation expense should be reflected by an equal change in accumulated depreciation because accounting records are maintained on a double entry system. He further stated that the Public Staff has taken the position in the past that any increase in the annual level of depreciation expense should result in an increase in accumulated depreciation, but with the situation reversed, the Public Staff has changed its position. Finally, Mr. Stonebraker testified that customers have not paid the Company for all the depreciation it has reflected on the books.

The Commission believes this issue is very similar to the accumulated deferred income tax issue in the Carolina Power & Light Company case referenced by Ms. Dietz. The Commission agrees with the Public Staff's position that the December 31, 1992, balance of accumulated depreciation represents monies which the ratepayers have already paid. If this balance were not deducted from rate base, the Company's ratepayers would be forced to pay a return on money they have already provided to the Company. The basis for setting rates in a general rate case is a historical test period. One necessary step in the ratemaking process is to determine the Company's original cost rate base. As stated in G.S. 62-133(c):

> The original cost of the public utility's property, including its construction work in progress, shall be determined as of the end of the test period used in the hearing and the probable future revenues and expenses shall be based on the plant and equipment in operation at that time.

Clearly, in the ratemaking process, rate base should reflect actual booked costs as of a certain point in time, plus, if appropriate, adjustments for known changes in rate base after that point in time. The inclusion of plant added during the first few months of 1993 in rate base in this proceeding is a perfect example of the types of departures from end-of-period rate base which are contemplated in G.S. 62-133(c), which states:

> ...the Commission shall consider such relevant, material, and competent evidence as may be offered by any party to the proceeding tending to show actual changes in costs, revenues, or the cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period...

The change in the level of annual depreciation expense will not cause the level of accumulated depreciation to decrease below its December 31, 1992, balance, unlike the increases in plant discussed above, which will cause the level of plant in service to increase above its December 31, 1992, balance. Therefore, the Commission concludes that the proper level of accumulated depreciation for use in this proceeding is the actual balance reflected on the Company's books at December 31, 1992, adjusted by the amount agreed to by the parties in the stipulation agreement related to storm damage costs, as discussed elsewhere in this Order.

The Commission further concludes that the decision in this case is not inconsistent with cases in which accumulated deprecation has been increased to reflect increases in annual depreciation expense. The reality of the situation is that accumulated depreciation is normally expected to grow over time. To reduce accumulated depreciation in this proceeding would be to turn a blind eye to that reality.

Cash Working Capital

The second area of difference between the parties is cash working capital. The parties agree that $1,041,872 should be included in cash working capital for investor funds advanced for purchased power. The remaining balance of cash working capital is calculated by the formula method which is 1/8 of operation and maintenance expense excluding purchased power. The difference in the parties' positions regarding cash working capital results from the different levels of operation and maintenance expense the parties have recommended. The Commission has determined elsewhere in this Order that the appropriate level of operation and maintenance expense to include in this proceeding is $13,140,462. Therefore, the Commission concludes that the appropriate level of cash working capital is $2,684,430.

As noted above, in its application, the Company has included an allowance for working capital calculated by the formula method (one-eighth of operation and maintenance expenses excluding purchased power), plus the Company has increased working capital to reflect the average investor supplied funds advanced for purchased power. In her testimony, Public Staff witness Dietz testified that the Company's proposal in this case to include working capital for purchased power is a deviation from traditional methods of calculating working capital. Ms. Dietz testified that if in the future the Company desires to depart from the formula method as traditionally applied, the Company should be required to prepare and file a detailed per book lead lag study to support its request.

The Commission notes that the Company and the Public Staff are in agreement as to the method to use in calculating the amount that should be included in working capital. The parties likewise agree for purposes of this case that working capital should be increased to reflect the average investor supplied funds advanced for purchased power.

The Commission deems it unnecessary to require Nantahala to perform a lead lag study before the method agreed upon in this case should be utilized in a future case. Lead lag studies are traditionally performed by companies larger than Nantahala. For smaller companies like Nantahala, the Commission historically has refrained from requiring a lead lag study and has instead relied upon the formula method for calculating working capital.

Nantahala is unique in the magnitude of the purchased power that it acquires, and purchased power increases each time an additional sale is made. The singular circumstances present in this case make it appropriate to adjust working capital by including an appropriate amount of investor supplied funds used for purchased power. Such unique circumstances also justify deviation from the traditional formula method. In addition, the cost of performing a detailed lead lag study is significant. The magnitude of the cost of conducting a lead lag study is one of the reasons for the Commission's refusal to require smaller companies to perform a lead lag study. We do not believe that the benefits to be gained by a formal lead lag study for Nantahala outweigh the substantial costs that would be incurred to perform such a study. One method of recognizing the investor supplied funds used for purchased power would have been to apply the formula approach to purchased power, which would have resulted in a much larger adjustment to working capital than the one proposed by the Company. Nantahala did not take this approach, but rather chose to do a lead lag study on this one component of expense. This allowed the Company to recognize the differences in timing of paying for and receiving payment for purchased power. It represents a good balance between the interests of Nantahala's customers and its stockholder. Therefore, we decline to adopt at this time the Public Staff recommendation that Nantahala perform a lead lag study before it is entitled to include the average investor supplied funds advanced for purchased power in a future case.

Deferred Debits

The next area of difference between the Company and the Public Staff is deferred debits. The following schedule summarizes the final positions on deferred debits of the Company and the Public Staff:

Item	Company	Public Staff	Difference
Prepaid insurance	$ 184,781	$ 184,781	$ -0-
Extraordinary repairs	515,987	515,987	-0-
Unamortized premium on debt	46,252	46,252	-0-
Prepaid pension costs	526,579	526,579	-0-
Franklin Dam repairs	1,749,885	1,749,885	-0-
Prior period taxes and regulatory fees	281,123	-0-	(281,123)
Part 12 expenses	276,115	-0-	(276,115)
Environmental clean-up costs	258,871	210,348	(48,523)
Pipeline painting	407,167	354,437	(52,730)
Unamortized rate case expense	114,000	-0-	(114,000)
1992 labor contract negotiation costs	78,905	-0-	(78,905)
Storm damage costs	2,934,888	2,934,888	-0-
Total deferred debits	$7,374,553	$6,523,157	$(851,396)

The parties agree on the appropriate levels of prepaid insurance, extraordinary repairs, unamortized premium on debt, prepaid pension costs, Franklin Dam repairs, and storm damage costs to include in deferred debits. Therefore, the Commission concludes the following amounts are appropriate and reasonable for use in this proceeding:

Item	Amount
Prepaid insurance	$ 184,781
Extraordinary repairs	515,987
Unamortized premium on debt	46,252
Prepaid pension costs	526,579
Franklin Dam repairs	1,749,885
Storm damage costs	2,934,888

The first difference in deferred debits between the Company and the Public Staff relates to prior period taxes and regulatory fees. As discussed elsewhere in this Order, the Commission has rejected the Company's proposed amortization of prior period taxes and regulatory fees. Therefore, inclusion of an unamortized balance in deferred debits is inappropriate.

The second difference in deferred debits relates to what amount, if any, should be included for Part 12 expenses. The Company and the Public Staff have agreed that one-fifth of the total cost of one round of Part 12 inspections should be included in operating expenses. The parties differ, however, on whether any amount should be included in rate base for unamortized Part 12 costs. The Public Staff has not included a deferred debit for unamortized Part 12 costs. In her pre-filed testimony, Public Staff witness Dietz stated that she did not believe rate base treatment was appropriate for several reasons: (1) the costs are incurred over a period of several years (the costs examined in this rate proceeding were incurred from 1987 through 1992), (2) the costs are expenses by nature, and (3) the costs have been incurred by the Company since the early 1980s.

Company witness Stonebraker argued in his rebuttal testimony that a cost large and unusual enough to be spread over several years for ratemaking purposes should be granted rate base treatment for reasons of fairness and equity. He also stated that the Company has to spend money in one or two years and recover it in rates over several additional years and that the Public Staff proposal effectively prevents the Company from earning a return on its "investment." According to Mr. Stonebraker, if the Part 12 inspection costs were incurred in one year, the amount would be over 24 percent of the Company's total hydro operating and maintenance expenses.

During cross-examination, Ms. Dietz testified that, based upon the information provided to the Public Staff by the Company, the Part 12 costs did not appear to be front-end loaded costs. Ms. Dietz further testified that the Public Staff considered the costs for an entire round of inspections and that those costs are incurred over a period of several years, not just one or two.

After careful consideration of the testimony on this adjustment, the Commission determines that the unamortized portion of the costs should be included in rate base. As with other items of substantial magnitude and materiality for which deferral accounting is provided, the Commission believes that accounting consistency requires that if only a pro-rata portion of the cost is recognized as an expense in the test year, it is appropriate to place the unamortized portion in rate base for the purpose of allowing the investor to earn a return on the unrecovered portion. By failing to include the unamortized portion in rate base, the Public Staff argues it is only making a normalization adjustment. The Public Staff has failed to persuade the Commission that allowing 1/5 of such a substantial cost in expenses as a normalization adjustment without allowing the unamortized balance in rate base is appropriate for a company the size of Nantahala. Regulatory and accounting consistency require that the remaining 4/5 of costs be placed in rate base for amortization treatment. Failure to do so will deprive the investor of a return on funds it has provided but will not recover for many years.

The third difference relates to the amount to include in deferred debits for environmental clean-up costs. The Public Staff has proposed to include an unamortized balance in deferred debits for the environmental clean-up costs at the storage site facility but not to include a deferred debit for the environmental clean-up costs related to vandalism. The Company believes that a deferred debit should be included for the unamortized balances for all environmental clean-up costs.

Public Staff witness Dietz testified that the Commission approved deferral accounting for environmental clean-up costs in Docket No. E-13, Sub 158. These costs were related to both clean-up at the storage site facility (approximately $243,000) and clean-up required by acts of vandalism against Company property (approximately $65,000). However, Ms. Dietz stated that she did not believe the costs related to the vandalism incidents should be given rate base treatment in this proceeding because these costs are representative of unforeseen maintenance and repair expenses which the Company should expect to incur from time to time. In its filing in Docket No. E-13, Sub 158, the Company specifically stated that its facilities are always subject to vandalism. Additionally, Ms. Dietz testified that the costs related to the vandalism are comparable in amount to costs the Commission concluded were not of sufficient magnitude to warrant deferral accounting treatment in Docket No. E-13, Sub 136. Ms. Dietz distinguished the vandalism costs from the storage site clean-up costs noting that the storage site clean-up was a non-recurring event and that the amount was of a sufficient magnitude to warrant deferral accounting treatment.

In his pre-filed direct testimony, Mr. Stonebraker testified that the 1992 costs incurred in connection with these one-time clean-ups had been included in rate base and expenses by the Company. In his rebuttal testimony, Mr. Stonebraker stated that the Public Staff's logic relating to this adjustment is "internally inconsistent" and its recommendation "one-sided." Nantahala received approval from the Commission to follow deferral accounting for all the environmental clean-up costs included in this rate case. Mr. Stonebraker argued that if the clean-up costs relating to the vandalism incidents are expected maintenance and repair costs, they should be recovered in their entirety in one year rather than over ten years with no rate base treatment for the unamortized balance. If the costs are extraordinary, then they should be amortized over a period of time with rate base treatment for the unamortized portion.

During cross-examination, Ms. Dietz testified that, although none of the parties nor the Commission's Order in Sub 158 separated the costs, it is appropriate to evaluate the vandalism costs separately from the storage site leakage costs because they are two totally unrelated events. She further stated that she attempted to include a representative level in expenses, not track a specific cost. Ms. Dietz compared the Public Staff's treatment of the vandalism costs to the Commission's treatment of the Surry maintenance costs in the North Carolina Power rate proceeding, Docket No. E-22, Sub 314. She stated that her treatment of these costs was consistent with the normalization approach taken by the Commission for Surry outage costs.

The Commission determines that both the unamortized portion of the 1992 environmental clean-up costs related to the vandalism and the storage site contamination should be included in rate base. Ms. Dietz's testimony suggests that the $65,000 cost for the environmental clean-up from the vandalism is the type of cost that the Company should expect from year to year. The Company has treated this item consistently with other items of substantial magnitude that historically have not occurred in each year and has sought to include only 1/10 of the cost as a test year expenditure. The Company's treatment is beneficial to ratepayers in that it spreads the recovery of this cost over ten years. The Public Staff agrees with reducing the expense by removing 90% of it, but argues that there should be no rate base treatment of the unamortized portion. It is clear that in the preceding accounting Order, Docket No. E-13, Sub 158, the Commission approved deferral accounting for all the environmental clean-up costs. It is the magnitude of the costs and the fact that the vandalism resulted in environmental damage that warrants deferred treatment in this case. Although vandalism indeed may be expected from year to year, it is unusual that the vandalism will require Nantahala to take steps to clean up the environment and expend $65,000 to fix the problem.

The fourth difference in deferred debits between the Company and the Public Staff relates to the amount to include in deferred debits for pipeline painting. Specifically, the Public Staff has recommended not allowing the unamortized portion of 1985 and 1986 painting costs to be included in deferred debits. In her direct testimony, Public Staff witness Dietz testified that the Company had expensed the 1985 costs on its books when incurred. The Company requested deferral accounting treatment for the 1986 painting costs in Docket No. E-13, Sub 136, but the Commission denied that request and ordered the Company to expense the costs on its books. Ms. Dietz testified that the Commission's Order in Docket No. E-13, Sub 136, did not provide for this issue to be reconsidered at some future date. Additionally, Ms. Dietz differentiated the 1985 and 1986 costs from the 1992 painting costs, which both the Public Staff and the Company have recommended be included in rate base, by discussing the significant difference in the magnitude of the dollar amount of the costs as well as by pointing out that the Commission has ordered that the 1992 painting costs be given deferral accounting treatment in Docket No. E-13, Sub 158.

In his rebuttal testimony, Company witness Stonebraker indicated that he did not think it was appropriate for a cost to be amortized in rates but not be given rate base treatment.

During cross-examination, Public Staff witness Dietz stressed that these painting costs are expense items by nature, and, as the Commission ruled in Docket No. E-13, Sub 136, the 1986 costs were not of such a magnitude to warrant deferral accounting treatment. Ms. Dietz also stated that ordering paragraph number four in Docket No. E-13, Sub 136, specifically identified two issues which were subject to review in a general rate proceeding, and the 1986 pipeline painting costs were not so identified.

During cross-examination, Mr. Stonebraker testified that the Order in Docket No. E-13, Sub 136, was an accounting Order and did not speak to the proper ratemaking treatment of the items addressed. However, he did agree that the Order did not specify that the Commission would revisit this issue.

The Commission has reviewed all of the testimony and evidence on this issue and concludes that the unamortized 1985 and 1986 pipeline painting costs should not be included in deferred debits. While it is true that the Order issued in Docket No. E-13, Sub 136, was an accounting Order, the Commission believes that in order for regulation to be fair and effective, it should be appropriately consistent. Therefore, the Commission believes it is not appropriate to include any amount in rate base for the 1985 and 1986 painting costs for the same reasons that deferral accounting was not approved in Sub 136. Had the Commission felt that future inclusion in deferred debits for ratemaking purposes was possible, it would have taken the initial step of approving deferral accounting when requested to do so in Sub 136. The Company and the Public Staff have agreed that $354,437 should be included in deferred debits for 1992 pipeline painting costs, and the Commission concludes that is reasonable.

The fifth difference in deferred debits relates to the amount to include, if any, in deferred debits for unamortized rate case expense. As set forth elsewhere in this Order, the Commission determined that the appropriate level of rate case expense to be amortized and included in operating revenue deductions is $72,667. The question now at hand is whether an "unamortized" balance should be included in deferred debits for rate case expense.

The essence of the disagreement between the Company and the Public Staff is whether the adjustment to amortize the rate case expenses over several years is a normalization of test year expenses or a setting aside of a specific cost for specific recovery. Public Staff witness Dietz testified that the intent of the Public Staff's adjustment was to normalize expenses. In her prefiled testimony, she stated that there are "...two approaches to amortization. In one approach the regulator explicitly creates a regulatory asset or regulatory liability to be amortized over a period of years." According to Ms. Dietz, this approach is appropriate for an unusually large item. She went on to explain that the other approach is normalization in which "...the regulator recognizes that the test year revenue and/or expense levels contain some abnormalities. The regulator's goal is to determine a representative level of this type of item for the purpose of setting rates. The regulator would not intend to create a regulatory asset or liability." Ms. Dietz concluded by stating that rate case expenses should be handled under the normalization approach because of their ordinary nature.

During cross-examination, when asked if the Public Staff position against including unamortized rate case expense in rate base was a different practice from what has been done in the past for Nantahala, Ms. Dietz testified that the Company did not request that any unamortized rate case expense be included in rate base in its last rate proceeding. Additionally, she testified that the Company had $136,000 for rate case expenses in its annual expense level from the Docket No. E-13, Sub 44, rate proceeding. Ms. Dietz also reiterated that she had attempted to set a representative level of expense and was not trying to specifically track the recovery of the rate case expenses incurred in conjunction with this case.

Mr. Stonebraker testified during his cross-examination that he believed the unamortized balance should be included in rate base because the Company is incurring the costs today but is not allowed to recover them today. Additionally, he stated that rate case expenses are not ordinary recurring test year expenses because they do not occur every year. Mr. Stonebraker further testified that the Commission has included unamortized rate case expense in rate base in many cases in the past.

On cross-examination, Ms. Dietz testified that she could not name a single case in which a public utility company had sought to amortize rate case expenses and the Commission had denied such treatment and instead treated rate case expenses as a normalized test year expense. Ms. Dietz could only list cases in which rate base treatment had not been requested for rate case expenses by larger companies or cases that were settled prior to being resolved by the Commission. The Commission notes that for smaller companies like Nantahala, that have no permanent rate departments that are engaged full time, year in and year out, in regulatory matters, the practice has been to treat rate case expenses as the Company has treated them in this case. We believe that this treatment is fair and should be continued. The Public Staff has offered insufficient justification for altering this long-standing policy based on its testimony in this case. Therefore the Commission concludes that the unamortized balance of Nantahala's rate case expenses should be included in rate base.

The final difference between the parties relates to the amount to include, if any, in deferred debits for 1992 labor contract negotiation costs. The Public Staff has recommended that no amount be included in deferred debits for labor contract negotiation costs. Public Staff witness Dietz testified that she believes her adjustment is appropriate because the costs are expenses by nature, resulted from no extraordinary circumstances, and given their total of $121,623, are not of any great magnitude.

In his rebuttal testimony, Company witness Stonebraker testified that the cost of the contract negotiations is large for a company the size of Nantahala. Furthermore, the costs are not ordinary because they are not incurred every year. Mr. Stonebraker also testified that these labor contract negotiation costs were expended in one year but benefit future periods. Therefore, the unamortized balance should be included in rate base so the Company can earn a return on its investment. Mr. Stonebraker also stated that if the Public Staff's position is adopted by the Commission, the Company would be forced to re-evaluate its negotiating approach and possibly move to having annual contracts, driving up the costs to ratepayers.

When Ms. Dietz was cross-examined on the potential for higher costs if the Company chose to negotiate annual contracts, she stated that she believed the Company had an obligation to keep costs as low as reasonably possible.

Mr. Stonebraker agreed during cross-examination that the Company had in fact expensed the costs of the labor contract negotiations on its books. He reiterated his belief that Nantahala's investor had made a three-year investment and should be permitted to receive a return on that investment. He also stated that the Public Staff position is not fair or equitable.

After reviewing the evidence, the Commission concludes that the Public Staff's adjustment to remove the unamortized balance of labor contract negotiation costs is appropriate. Labor contract negotiation costs are an expected cost of doing business in a union environment such as is faced by many electric utilities. The Commission does not share Mr. Stonebraker's opinion that a cost is not ordinary if it is not incurred every year. Furthermore, the magnitude of the contract negotiation costs is comparable to other amounts for which the Commission has not permitted deferral accounting treatment. It is inevitable in any business that costs will fluctuate from year to year and that certain costs may be incurred in one year but not in the next. The Commission does not believe it is desirable or even possible to track all of those costs. The Commission concludes that these labor contract negotiation costs are more appropriately accounted for by the normalization approach in which a representative level is included in expenses.

The Commission therefore concludes that total the level of deferred debits to include in rate base for purposes of this proceeding is $6,993,128.

Deferred Credits

The fourth area of difference between the Company and the Public Staff relates to the proper amount of deferred credits to include in rate base. The $(965,995) difference between the parties is itemized below:

Item	Company	Public Staff	Amount
Accrued taxes	$(658,280)	$ (701,534)	$ (43,254)
Unamortized gain on sale of land	0	(922,741)	(922,741)
Total	$(658,280)	$(1,624,275)	$(965,995)

The first item in deferred credits on which Nantahala and the Public Staff disagree is accrued taxes. Public Staff witness Dietz testified that she made two adjustments to the December 31, 1992, balance used by the Company. She removed one-half of the balance of county property taxes because those taxes are accrued throughout the year but are only paid at the end of the year. She also adjusted accrued federal and state income taxes to reflect a twelve-month average as opposed to the December 31, 1992, balance.

During cross-examination, when questioned on the number of methods used to compute the level of accrued taxes to include in this proceeding, Ms. Dietz testified that what is important is arriving at a representative level. She further stated that the debit balances presented by the Company for accrued federal and state income taxes were obviously not representative. She also reiterated that, due to the payment practices associated with property taxes, the December 31 balance of accrued property tax is the highest balance of the year. During redirect, Ms. Dietz further explained that her adjustment to reduce accrued property taxes actually benefitted the Company because a smaller amount was deducted from rate base.

Mr. Stonebraker addressed this issue on rebuttal. He testified that the Public Staff has made an adjustment to what is termed a more representative level. This was done by using three different methods depending on the type of tax. Mr. Stonebraker testified that if actual year-end amounts are not used, a better method would be to determine the average amount of all accrued taxes using each month-end balance for 12 months. The month-end balance is the actual amount of funds provided by ratepayers which has not been remitted to a government. Thus, this is the money from customers the Company has available for use. Mr. Stonebraker testified that another advantage of that method is that each type of tax is treated the same way. The Company adopted this method in its proposed order.

The Commission has carefully examined the differences between the parties on this issue. The Commission determines that it is appropriate for purposes of this proceeding that the amount of all accrued taxes should be determined by using each month-end balance for 12 months. Both parties use this method for accrued state and federal income taxes and the Commission concludes that such method will result in a reasonable and representative level of accrued taxes.

The other area of disagreement in deferred credits between the Company and the Public Staff relates to the gain realized on 1988 land sales. Public Staff witness Dietz testified that during 1988, the Company sold several parcels of land, the majority of which had been included in rate base prior to 1986. She recommended that 100% of the gain be flowed back to ratepayers because they bore the costs and assumed the risks associated with the land once it was included in rate base. Ms. Dietz further testified that her recommendation is consistent with the Commission's treatment of gains on sale or transfers of utility plant in gas, electric, and telephone cases and provided a list of docketed matters to support her claim.

In his rebuttal testimony, Company witness Tucker stated that the Public Staff proposal to flow the gain on the sale of land to the ratepayers is untimely and unfair and is punitive to Nantahala's current stockholder. He further testified that the sale of the land was fully discussed during the docket that dealt with the sale of Nantahala's stock from Alcoa to Duke, and the question of customers receiving the gain was not raised in that docket. Additionally, Mr. Tucker stated that the proceeds of the sale were invested in plant in service. When Duke purchased the stock of Nantahala, it paid for the increased plant so Alcoa effectively has received the gain. Furthermore, ratepayers have benefitted from the transfer of the stock from Alcoa to Duke, and the handling of the gain was an integral part of the structuring of the deal.

Company witness Stonebraker stated in his rebuttal testimony that he did not agree with the customers receiving the gain from the sale of land. Although the land was at one time included in rate base, the customers never paid for the land itself. They paid a fee for the use of the land. He further testified that the proceeds of the sale were invested in electric plant and that the current stockholder has never received a dividend. Therefore, the ratepayers have received the benefit of the sale. Additionally, Mr. Stonebraker stated that this is a classic example of retroactive ratemaking.

In general, the Commission believes that it is appropriate for ratepayers to receive the benefits of the sale of property which has been obtained by the utility in the course of its utility business. Nevertheless, after carefully reviewing the evidence in this docket and the record of Docket No. E-7, Sub 427, the Commission concludes that the gain from the 1988 sale of land should not be flowed back to ratepayers in this proceeding. The unique facts of this case support this conclusion. By Order entered in Docket No. E-7, Sub 427, on August 29, 1988, the Commission approved Duke Power Company's application to purchase the stock interest of the Aluminum Company of America (Alcoa) in Nantahala. In approving the application, the Commission specifically found and concluded that the acquisition of Nantahala by Duke would be beneficial to Nantahala and Duke and their respective customers. The Commission further found that for approximately 15 years, Nantahala's regulatory proceedings had become far more burdensome and controversial than was appropriate due to Nantahala's affiliation with Alcoa and that the Company's three rate cases since 1976 had been the source of long, bitter, and expensive controversy. The Commission concluded that approval of Duke's application would remove the sources of conflict that had plagued the relationship between Nantahala and its customers over the years. The Public Staff supported the proposed stock sale and recommended that it be approved. All of the other parties to the Sub 427 case also favored the sale of Nantahala's stock by Alcoa to Duke.

In effect, the sale of the land in question was a condition required by Alcoa to permit the sale of the stock in Nantahala to take place. The 1988 sale of property occurred immediately prior to the sale of Nantahala's stock to Duke by Alcoa. In fact, the stock sale precipitated the property sale. Duke had no need for nor any interest in purchasing that property at fair market value. Alcoa required Nantahala to dispose of the property at auction. The proceeds of the property sale were thereafter invested in plant to serve customers. This increased the retained earnings in Nantahala and thus increased the sale price of the stock. In effect, Duke paid the net value of the property sold, and the beneficiary of this payment was Alcoa, who received the value of the property sold in cash from Duke as a result of the stock sale.

While the Commission agrees with the Public Staff that we retain the authority to flow through, in whole or in part, the gain on sale at issue in this proceeding to ratepayers, the singular facts of this case simply do not justify taking that action. The sale of Nantahala's stock to Duke has proved to be a substantial benefit to Nantahala's customers, both in terms of increased reliability and a decrease in costs. In fact, customers are better off after the sale even if they do not receive the flow through of the 1988 land sale profits. Alcoa was the recipient of the gain on the land sale. It would be unfair to in effect penalize Nantahala's current stockholder, Duke Power Company, by now requiring a flow through of the gain on sale.

The Public Staff cites examples of cases where the Commission has flowed through gains from the sale or disposition of assets. These cases are distinguishable from the sale at issue in this case. In the cases cited by the Public Staff, the sale or disposition was not made in conjunction with and as an integral part of a sale of the utility itself. In this case, Alcoa divested itself of its entire holdings in Nantahala. Alcoa's sale equates to a total liquidation. Because the sale of land was an essential element of the liquidation, and considering the singular facts of this case, it is reasonable to deny flow through of the gain to ratepayers. This result is appropriate because the entity divested of the profit here would be Duke, not Alcoa. This is a unique case because it is clear that Nantahala's ratepayers are better off after the sale even if cost of service is not reduced by a flow through of the gain from the sale of land. Therefore, good cause exists to reject the Public Staff's proposed ratemaking adjustment.

As a result of the Commission's decision that Nantahala should retain 100% of the land sale gain, it is not appropriate to amortize the gain or deduct the unamortized net-of-tax balance of the gain from rate base.

The Commission therefore concludes that the total level of deferred credits to be deducted from rate base for purposes of this proceeding is $658,280.

Accumulated Deferred Income Taxes

The parties differ on the level of accumulated deferred income taxes because they have different positions on the level of deferred debits. The levels of accumulated deferred income taxes recommended by the Company and the Public Staff are set forth in the following table:

Item	Company	Public Staff	Difference
Part 12 expenses	$ (108,144)	$ 0	$108,144
Environmental clean-up costs	(101,390)	(82,385)	19,005
Pipeline painting	(164,786)	(138,820)	25,966
Rate case expense	(44,650)	0	44,650
Labor contract negotiation costs	(30,904)	0	30,904
All other	(9,364,444)	(9,364,444)	0
Total	$(9,814,318)	$(9,585,649)	$228,669

The Commission has earlier determined the appropriate level of deferred debits. Based upon the conclusions reached regarding the appropriate level of deferred debits, the Commission concludes that the reasonable level of accumulated deferred income taxes to be deducted from rate base is $9,769,719.

Other Cost-Free Capital

The parties have agreed on the amount of other cost-free capital to include in this proceeding. The Public Staff made an adjustment which affected the manner in which cost-free capital was presented in the schedules. This adjustment had no revenue impact. The Commission concludes that including cost-free capital on the schedule detailing rate base as opposed to the schedule detailing capital structure provides a clearer and more easily understood presentation, consistent with the current practice of the Commission.

The Commission concludes that the Company's rate base used and useful in providing service to its North Carolina retail customers for purposes of this proceeding is $68,576,541, made up of the following components:

Item	Amount
Electric plant in service	$131,964,517
Accumulated provision for depreciation	(63,824,525)
Net electric plant in service	68,139,992
Materials and supplies	2,045,942
Cash working capital	2,684,430
Deferred debits	6,993,128
Deferred credits	(658,280)
Customer deposits	(343,737)
Accumulated deferred income taxes	(9,769,719)
Other cost-free capital	(515,215)
Total rate base	$ 68,576,541

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33-35

The evidence for these findings of fact is based on the testimony and exhibits of Company witness Stonebraker and Public Staff witness McLawhorn.

Witness Stonebraker filed testimony and exhibits adjusting per book sales and revenues related to customer growth and weather normalization for the test period ending December 31, 1991, and subsequently updated through the period ending December 31, 1992. His adjustment is $557,786 based on an adjustment of 14,204,973 kWh of additional sales.

Witness McLawhorn filed testimony and exhibits adjusting per book sales and revenues related to customer growth and weather normalization for the test period ending December 31, 1991, through the update period ending December 31, 1992. His adjustment is $539,859 based on an adjustment of 14,933,268 kWh of additional sales. Witness McLawhorn's adjusted revenues are exclusive of sales tax revenues which were included in the Company's prefiled revenues. The Company accepted the Public Staff's proposed numbers.

The Commission concludes that the Public Staff's adjustment for customer growth and weather normalization is reasonable and appropriate for use in determining the end-of-period level of kWh sales and revenues. The appropriate adjustment to revenues for the period ending December 31, 1991, through the update period ending December 31, 1992, due to customer growth and weather normalization is $539,859 based on additional sales of 14,933,268 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Stonebraker and Public Staff witness McLawhorn and is uncontested in this case.

The adjusted level of sales for the test period through the update period ending December 31, 1992, of 760,415,678 kWh consists of the following components:

	kWh
Per Book Sales	745,482,410
Customer Growth Adjustment	13,724,236
Weather Normalization Adjustment	1,209,032
	760,415,678

Based on the evidence presented, the Commission concludes that the appropriate adjusted test year level of sales through the December 31, 1992, update period is 760,415,678 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence for this finding of fact is found in the testimony of Public Staff witness Turner, Supplemental Exhibit BRT-1, page 1 of 1. This exhibit shows the level of basic rate schedule revenue (not including purchase power revenue) for the North Carolina retail jurisdiction to be $19,492,814. This determination of revenue by witness Turner was not contested by any party of record, and the Commission concludes that this level is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 38-39

The evidence supporting these findings of fact is included in the testimony and exhibits of Company witness Stonebraker and Public Staff witness Dietz.

In her prefiled testimony, Ms. Dietz described an arrangement whereby Nantahala purchases and resells power between Duke Power and TVA on an as-needed basis. Ms. Dietz testified that a majority of the months since the contracts were signed have had at least one transaction of this type resulting in profit to Nantahala. Therefore, Ms. Dietz made an adjustment to include the actual 1992 revenue resulting from this type of transaction as a representative level for this proceeding.

In his prefiled direct testimony, Mr. Stonebraker testified that the Company had not included any amount in its filing for these transactions because of their uncertain nature. In his rebuttal testimony, Mr. Stonebraker again stated that no amount should be included in this proceeding for the purchase and resale of power because the revenue was too uncertain. He also characterized the revenue as an estimate and stated that the Public Staff was inconsistent, unfair, and unreasonable for including estimated revenue while not including estimated expenses. He went on to state, however, that if the Commission determines some level of revenue should be included for these "wheeling" transactions, the Commission should consider using an average over the life of the contract, because one transaction in 1992 represented 70% of the 1992 revenues.

During cross-examination, Ms. Dietz reiterated that a majority of the months since the contracts between Nantahala, Duke, and TVA were signed have had transactions involving the purchase and resale of power resulting in profit to Nantahala. She went on to state that she had asked the Company for an explanation of the one large sale in April 1992, and its response was essentially that the Company did not know why this transaction occurred. Ms. Dietz testified that the Company response provided her with no evidence that the 1992 level of revenue was not representative. When asked if she would object to using more months to calculate an average amount of revenue to include in this proceeding, Ms. Dietz stated that she believed the Public Staff would object to going back to May 1991 to calculate an average. According to Ms. Dietz, a consistent pattern of revenues did not emerge until November 1991. Ms. Dietz also pointed out that the twelve-month period she had used contained three months in which no "wheeling" transactions occurred.

During his cross-examination, Mr. Stonebraker agreed that between May 1991 and December 1992, twelve out of twenty months had at least one of these transactions involving the purchase and resale of power. He also agreed that between November 1991 and December 1992, eleven out of fourteen months had at least one of these type of transactions. However, Mr. Stonebraker again stated that it is the Company's position that no amount should be included in this proceeding for this type of revenue because the Company has no control over the actions that cause the revenue to be generated.

Based on the evidence, it is apparent to the Commission there is a stream of revenue flowing to the Company as a result of its contracts with Duke Power and TVA to purchase and resell power. Both Company witness Stonebraker and Public Staff witness Dietz testified that Nantahala has had at least one transaction in a majority of the months since the contracts were signed. However, the Commission is mindful of the uncertainty that exists as to a reasonable and representative level of such revenues. Based upon such uncertainty and the limited duration of these contracts, the Commission deems it appropriate for the Company to defer such revenues beginning on and after the date of this Order pending its next general rate case proceeding at which time the Commission will again address this matter. Further, the Commission considers it appropriate in the interim for the parties to investigate the feasibility and appropriateness of the inclusion or tracking of these revenues in the context of the Company's purchased power adjustment proceeding and further address this issue in Nantahala's next rate case proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40

The evidence for this finding of fact is found in the testimony and exhibits of various witnesses representing the Company and the Public Staff.

Total operating revenue for the test period through the update period ended December 31, 1992, is $23,972,903. The elements of basic rate schedule revenue, weather normalization and customer growth adjustments, amortization of the gain on sale of land and "wheeling" revenues are discussed elsewhere herein.

The evidence related to the appropriate level of other uncontested miscellaneous revenues of $717,289 is found in the testimony and exhibits of Public Staff witness Turner including his Exhibit BRT-2, page 1 of 1, as well as his supplemental and revised Exhibit BRT-2, page 1 of 1. These numbers were not contested by any party of record and agree with data provided by the Company through its filing and with workpapers provided by the Company to members of the Public Staff.

Based on the foregoing, the Commission concludes that other uncontested miscellaneous revenues as detailed below are reasonable and appropriate for use in this proceeding:

Description	Revenues
Late Payment	$98,438
Miscellaneous Service Revenues	87,412
Rent on Electric Property	456,433
Other Electric Revenue	26,170
Amortized Inventory Adjustment	48,836
	$717,289

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-58

The evidence supporting these findings of fact is included in the testimony and exhibits of Company witnesses Stonebraker and Robinson and Public Staff witnesses Dietz and McLawhorn.

The levels of operating revenue deductions (excluding purchased power expense) proposed by the Company and the Public Staff representing their final positions are set forth in the schedule below:

Item	Company	Public Staff	Difference
Operation and maintenance expense	$13,347,549	$13,121,191	$(226,358)
Depreciation expense	3,813,761	3,081,983	(731,778)
Taxes other than income taxes	1,374,636	1,374,636	0
Interest on customer deposits	19,199	19,199	0
Charitable contributions (net of tax)	24,872	0	(24,872)
Income taxes	999,230	1,417,403	418,173
Total operating revenue deductions	$19,579,247	$19,014,412	$(564,835)

As can be seen from the above schedule, the Company and the Public Staff agree on the amounts to be included in operating revenue deductions for taxes other than income taxes and interest on customer deposits. The Commission thus concludes that the levels of taxes other than income taxes and interest on customer deposits appropriate for use in this proceeding are $1,374,636 and $19,199, respectively.

Operation and Maintenance Expense

The first area of difference between the Company and the Public Staff is operation and maintenance expense. The difference of $(226,358) is composed of the following Public Staff adjustments:

Item	Amount
Adjustment to remove amortization of undercollection of taxes	$(140,562)
Adjustment to self-insurance reserve for general liability claims	(19,463)
Adjustment to conservation education expense	(25,000)
Adjustment to rate case expense	(41,333)
Total	$(226,358)

The first adjustment made by the Public Staff concerns what amount, if any, should be included in current operating revenue deductions for prior period taxes and regulatory fees the Company asserts it has not recovered from ratepayers. Ms. Dietz testified that, in Docket No. M-100, Sub 122, the Company requested an increase in rates to flow-through to ratepayers increases in various taxes as well as the imposition of the regulatory fee. The Commission determined that the increases requested by the Company were insubstantial and would be more properly considered in the context of a general rate case where all elements of the cost of service would be examined. Consequently, the Commission denied the Company's application to adjust its rates. In this proceeding, the Company has calculated the amount of revenue it would have collected for 1991, 1992, and the first quarter of 1993 had its request in Docket No. M-100, Sub 122 been approved. The Company has made a pro-forma adjustment to amortize this amount for the "undercollection of taxes" over three years and include the amortization in operating expenses and the unamortized balance in rate base. Witness Dietz testified that the Company's action in this proceeding is an attempt to circumvent the Commission's decision in Docket No. M-100, Sub 122, and also effectively constitutes retroactive ratemaking. Therefore, she removed the Company's pro-forma adjustments.

In his pre-filed testimony, Mr. Stonebraker testified that in Docket No. M-100, Sub 122, the Commission stated that all the criteria were met for an increase in rates, but that the impact on rates was insubstantial. As a result, Nantahala was not permitted to raise its rates and was forced to spend investor funds to pay the taxes. Mr. Stonebraker argued that the Company should now be made whole for reasons of equity. In his rebuttal testimony, Mr. Stonebraker further testified that the Company had an unquestioned and uncontested increase in tax costs in 1991 which the Commission said should be considered in the context of a general rate case such as this case. Additionally, Mr. Stonebraker argued that the Public Staff is inconsistent in its determination of what constitutes retroactive ratemaking. Specifically, he compared the Public Staff's inclusion of prior period revenues for 1988 land sales with Nantahala's inclusion of prior tax expenses.

During cross-examination, Public Staff witness Dietz testified that the Commission's Order in Docket No. M-100, Sub 122, did not leave this issue to be decided in a future rate case. Rather, the Commission merely pointed out that the appropriate place to consider this type of item is a general rate case proceeding. Additionally, the Commission's Order did not include a mechanism for recovering lost revenues in a future rate case.

The Commission has carefully reviewed the testimony of both parties and concludes that the Company's adjustment does in fact effectively constitute retroactive ratemaking. It is clear that the taxes and regulatory fees the Company seeks to recover in future rates were period costs of past years. Moreover, these taxes and regulatory fees are inherently and naturally related to the specific periods in which they were incurred. In contrast, the timing of the land sale was at the Company's discretion and could have related to any period. Furthermore, this issue was decided by the Commission in Docket No. M-100, Sub 122, and no new evidence has been presented that causes the Commission to change its Order in that docket. Therefore, the Commission concludes that no amount should be included in current operating expenses for these prior years' taxes and regulatory fees.

The second adjustment made by the Public Staff relates to the appropriate annual amount to include in operation and maintenance expense for the self-insured portion of the Company's general liability insurance.

Company Witness Stonebraker in his direct pre-filed testimony stated that Nantahala's general liability insurance coverage includes a $250,000 deductible per occurrence. This means that the Company is self-insured up to $250,000 per occurrence. Nantahala has investigated the possibility of lowering the deductible and has found that it would cost approximately an additional $35,000 to have a $100,000 deductible and $68,000 to have a $50,000 deductible.

Mr. Stonebraker testified that in the past the Company has expensed uninsured damage claims on a pay-as-you-go basis. However, as juries in general continue to issue increasingly large damage awards, the practice of pay-as-you-go for Nantahala is outdated. He stated that a large claim may occur at any time, and it would be improper to include the full claim amount in test period expenses if the claim is paid in a test year. Only a portion of the claim amount should be included. By the same token, it would not be fair for the stockholder to bear the entire amount if a large claim is not in the test year. Mr. Stonebraker expressed the opinion that these costs should be deferred and included in rates over several years.

The Company proposed to adopt the reserve method of accounting and ratemaking for the self-insured portion of the general liability coverage. The Company made an adjustment of $50,000 or $48,658 on a North Carolina retail basis to increase test year expenses to reflect one-fifth of the deductible. Mr. Stonebraker stressed that this would charge customers, over a period of time, a sufficient amount to allow the Company to pay claims under the self-insured amount. The amounts, if any, collected from customers that are not paid out in claims would be deducted from rate base in future rate cases. If claims paid exceed amounts collected, the excess would be added to rate base.

Public Staff witness Dietz endorsed in concept the reserve method for the self-insured portion of the liability insurance reserve. However, she recommended, based on responses the Public Staff received from the Company regarding claims history, that only $30,000 or $29,195 on a North Carolian retail basis be included in operation and maintenance expense. She stated that this amount was calculated by determining the average claim per year for the period

1982 through 1992. Thus, she reduced the self-insurance reserve for general liability claims by $19,643.

In rebuttal, Mr. Stonebraker testified that in management's judgment, based on claim history, pending claims, etc., a five-year period should be used to arrive at a balance to cover one claim. He stated that this is fair to all parties.

Mr. Stonebraker objected to the fact that the Public Staff has only looked at the Company's historical record of claims in recommending the $30,000 annual addition to the reserve which would fund it over eight years. Mr. Stonebraker stressed that the same responses to Public Staff data requests which provided the claims history also explained in detail two cases which are currently being pursued against the Company. Both of these claims are in excess of the $250,000 deductible, so the Company is facing a total liability of $500,000, plus expenses, to defend itself. He testified that Nantahala will defend itself as well as it can, but, in all probability, substantial amounts will have to be paid by the Company. Even if the Company litigates and wins, the Company's costs will be substantial. For this reason, Nantahala stresses that the $30,000 per year proposal of the Public Staff is too low.

Based upon this testimony, the Commission determines that it is appropriate to approve the reserve method for funding the self-insurance reserve for general liability claims as is done for many other utilities under our jurisdiction. The Commission agrees with the Company that it is appropriate to fund this reserve with $50,000 per year, which is determined by taking one-fifth of the deductible for one claim. The Company seeks to accumulate funds in the reserve that will be available if the Company is required to pay the full deductible amount based on one claim in any given year. The Public Staff takes the position that there should be only enough in the reserve to cover what has historically been claimed in any given year. If the reserve is only funded by the amount that is expected to be paid in any given year, the reserve will not accumulate, and there will be nothing in the reserve to pay a substantial damage award should it occur.

Furthermore, the history of claims going back as far as the Public Staff has gone is not necessarily indicative of the claims that will be expected in the future. As stressed by Mr. Stonebraker, even now, the Company faces two substantial claims. Also, inflation and the propensity of juries to approve larger damage awards indicate that such claims and payments will likely increase in the future. In addition, Nantahala is responsible for paying not only the first $250,000 in a damage award, but the Company must also contribute to expert witness fees and other costs of litigation.

The Commission determines that in order to implement the reserve method as intended it is appropriate to fund the reserve by one-fifth of the deductible each year or by approximately $50,000 on a total company basis or $48,658 on a North Carolina retail basis. The Commission recognizes that if the reserve method is not selected the Company may be forced to lower the deductible and increase the annual insurance premium. We agree with the Company that this would increase costs to ratepayers in the long run and believe that the alternative requested by the Company is reasonable under these circumstances. So as to treat customers and the Company fairly, the balance in the insurance reserve will adjust rate base in future cases, plus or minus.

The third difference between the Company and the Public Staff relates to the Public Staff's adjustment to remove estimated conservation education expenses. Public Staff witness Dietz testified that she removed this estimated amount because "It is not appropriate to include in rates an amount that the Company has not spent, but rather merely estimates it may spend at some point in the future." Ms. Dietz further testified that the Company has no NCUC-approved load management programs other than the residential conservation discount.

In his direct testimony, Mr. Stonebraker testified that he had made an adjustment to include the Company's estimated increase in out-of-pocket costs for its conservation education program. Mr. Stonebraker also testified that any reduction in peak load or energy requirements will reduce purchased power costs. This reduction will be passed along to customers through the purchased power adjustment. Because customers are receiving the benefit, they should pay for the costs of the conservation education program. Additionally, Mr. Stonebraker testified that the costs of Nantahala's conservation education program have to be included in rates before they are spent so that the Company is not forced to spend money it cannot recover. He also stated, "If the Commission wants Nantahala to spend money to educate customers to reduce usage, the Commission must give the Company sufficient rates to recover its costs." Mr. Stonebraker further testified that the position taken by the Public Staff is "not equitable" and is "inconsistent."

During cross-examination, Ms. Dietz testified that, based on her investigation, there was no guarantee that costs will ever be incurred for conservation education. Furthermore, even if the costs are incurred, Ms. Dietz testified that she had no idea when that would be. Ms. Dietz reiterated that the Company has no programs in place and was not incurring any costs related to conservation education through the end of 1992. When asked if she thought it was fair to deny the Company's request, Ms. Dietz responded that she did not believe it was fair for ratepayers to be charged for a cost the Company has not and may not incur. Furthermore, she testified that the Public Staff had not removed any of the Company's advertising expense which referenced both safety and conservation information being available from the Company. Ms. Dietz concluded her cross-examination by stating that she did not believe the Public Staff was sending the Company inconsistent signals.

Mr. Stonebraker agreed during cross-examination that the Company has not yet spent the money on conservation education it has requested in this proceeding. However, Mr. Stonebraker stressed that the Company's ratepayers will receive 100% of the benefit of any reduction in purchased power cost. He further testified that, under the Public Staff proposal, the Company will lose any money that it spends for conservation education prior to its next rate proceeding. Mr. Stonebraker did agree, however, that the Public Staff proposal is consistent with the way every other utility is treated when it spends money between rate cases.

The Commission concludes that the Public Staff adjustment to remove estimated conservation education expense is appropriate. Both witnesses testified that the amount the Company sought to include is an estimate. Furthermore, Ms. Dietz testified that the Company has no conservation education programs in place and had incurred no cost related to conservation education through the end of 1992. It is apparent from the testimony that the cost the Company wishes to include for conservation education expense was not incurred during the test year. Furthermore, no evidence was presented to indicate that an actual change in costs had occurred prior to the close of the hearing. Therefore, this Commission has no alternative but to conclude that the Public Staff's adjustment to remove estimated conservation education expense is appropriate.

However, the Commission further concludes that it is appropriate to allow the Company to defer such costs, if in fact such costs are incurred. Such deferral shall pertain to only those costs which exceed those advertising costs which reference both safety and conservation information which has been included in the cost of service in this proceeding. The ratemaking treatment of any balance in the deferred account pertaining to these costs will be addressed in the context of Nantahala's next general rate case proceeding.

The final difference between Nantahala and the Public Staff with regard to operation and maintenance expense relates to the Public Staff adjustment to the annual level of rate case expenses. Public staff witness Dietz testified that she made two adjustments to the level of rate case expense the Company is proposing. First, she removed $10,000 that the Company had included for the cost of consultants to be hired by the Public Staff. Ms. Dietz testified that the Public Staff has not hired any consultants in connection with this proceeding and, to her knowledge, has no plans to do so. Ms. Dietz also testified that she amortized total rate case expense over a period of three years in an attempt to arrive at a representative annual level as opposed to the two-year amortization proposed by the Company.

In his direct testimony, Company witness Stonebraker testified that the Company had amortized the estimated cost of this rate proceeding over two years. Mr. Stonebraker testified that a two-year amortization period was selected because the Company anticipates its next rate proceeding will be in approximately two years. Mr. Stonebraker testified during cross-examination that the Company would be willing to remove $10,000 from total rate case expenses if the Commission guarantees that the Company will never be billed for costs of Public Staff consultants associated with this proceeding. In its proposed order in this docket, the Company has removed the $10,000 from rate case expense.

During cross-examination, Ms. Dietz testified that the Public Staff had attempted to set rate case expense, as well as the account in which it is recorded (Account 928), at a representative level. Ms. Dietz also testified that she had used the three-year amortization period as a way to arrive at a representative level although that amortization period was not an indication of how long the Public Staff expects it to be before the Company has its next rate proceeding.

After reviewing the evidence presented, the Commission concludes that the level of rate case expense for this proceeding is $218,000 which should be amortized over a period of three years. The use of a three-year amortization period is consistent with prior Commission decisions in this regard and will allow the Company to recover a reasonable and representative level of rate case expense. Accordingly, the appropriate level to include in operation and maintenance expense for purposes of this proceeding is $72,667.

Nantahala and the Public Staff have agreed in their stipulation that the annual level of storm damages to be included in this proceeding is $326,099. The

Commission approved the parties' stipulation and therefore concludes that this amount is reasonable.

One final adjustment is necessary regarding to level of operation and maintenance expense to include in this proceeding. The Company has agreed to the level of regulatory fee as proposed by the Public Staff. However, inasmuch as the Commission has rejected the Public Staff adjustments relating to the proper level of "wheeling" revenues and amortization of the gain on sale of land, the Commission finds it appropriate to adjust the level of regulatory fees in this proceeding. Accordingly, the Commission will reduce the level of regulatory fees by $192 in arriving at an appropriate level of operation and maintenance expense for purposes of this proceeding.

The Commission concludes that the appropriate level of operation and maintenance expense to include in this proceeding is $13,140,462.

Depreciation Expense

The second area of difference between the Company and the Public Staff is depreciation expense. Mr. Robinson testified that the depreciation study, completed under his direction, was performed by analyzing the Company's historical data along with consideration of future factors which are anticipated to have an impact upon the useful life of the Company's property. As part of the study process, Mr. Robinson completed interviews with the Company management to discuss future plans. He inspected physical property for a representative portion of the property owned by the Company.

The Company is in the midst of a significant construction program to upgrade and replace much of its aged and loaded transmission plant. In addition, the Company will also be replacing aged and loaded segments of distribution and general property.

Mr. Robinson testified that the historical life analysis was completed using standard techniques using accounting data from the Company's books and records. Using the results of the study, Mr. Robinson developed recommended depreciation rates based upon the continued use of the straight line method, broad group procedure and whole life technique. He testified that these approaches are utilized and recognized as appropriate throughout the utility industry. The results of the study, according to Mr. Robinson, along with the descriptions of the methods, procedures and techniques utilized in the study as well as factors considered in development of recommended average service life and average salvage factors were appropriate for use in this case.

The net result of the comprehensive service life study, when applied to the Company's December 31, 1991, plant in service, exclusive of Section 124 and 124(a) property, results in a proposed composite depreciation rate of 3.58%, as compared to the present composite depreciation rate of 4.56%. Applied to the actual December 31, 1991, plant in service of $92,457,188, the rate produces annual depreciation expense of $3,307,307.

Mr. McLawhorn, testifying for the Public Staff, stated that he found the depreciation technique currently used by Nantahala and proposed for continuation in the AUS study to be unsatisfactory and inconsistent with depreciation practices approved for other utilities in this jurisdiction. Mr. McLawhorn urged the Commission to switch to the remaining life technique as opposed to the whole life technique. Mr. McLawhorn testified that the whole life technique utilizes the average service life of the account over which to recover the original cost of depreciable property without consideration of the level of accruals that have occurred in the prior periods. He stated that the remaining life technique utilizes the remaining life of surviving property in an account to allocate only the undepreciated portion of the original cost of depreciable property, thus giving due consideration for accruals that have occurred before.

Mr. McLawhorn testified that the remaining life technique provides a more forward looking approach and that the remaining life technique's inherent systematic treatment of depreciation reserve imbalances that occur from time to time is advisable.

Mr. McLawhorn testified that the AUS study showed a theoretical reserve of approximately $30.2 million versus the actual per books amount of $47.6 million. Mr. McLawhorn stated that this shows that the current reserve is over-accrued by approximately $17.4 million based on current estimates of service lives and net salvage amounts — an excess of 57.6%. He testified that use of the remaining life technique allows for rapid corrective action to the reserve imbalance.

Mr. McLawhorn advanced several theories as to why the accumulated depreciation reserve could have become out of line. Mr. McLawhorn recommended annual depreciation expense with his proposed rates of $2,487,260 based on December 31, 1991, depreciable plant in service.

Mr. Robinson testified in rebuttal to Mr. McLawhorn. He testified that the whole life technique is currently used and/or accepted by a large number of utility companies and regulatory agencies throughout the United States. Mr. Robinson testified that the use of average remaining life based depreciation rates is not desirable or appropriate for Nantahala at this time. He listed several reasons why the Company's book depreciation reserve is relatively high as compared to its current plant in service. He stated that the Company's past retirements have been lower than they should have been. This circumstance occurred because of Nantahala's long heritage as a subsidiary of an industrial firm. Under the direction of industrial company management, Nantahala's accounting policies and procedures differed somewhat from those typically utilized by utilities. For example, various units of property were replaced and charged to maintenance expense in lieu of retiring the old property and capitalizing the new facilities. This accounting approach results in both the gross plant investment being understated, since a surviving investment includes only the cost of the old original property instead of a newer replacement property, and overstates the reserve because of the lack of retirements.

Mr. Robinson testified that the Company's management changed the Company's past accounting policy and procedures of replacing fixed capital property via maintenance expense during the 1987 — 1988 time frame. Further, the resulting lower level of retirements produces longer life indications, plus the reserve continues to build since the older property was not retired.

Mr. Robinson testified to other reasons why the Company's depreciation reserve has grown to its current level. In addition to the fact that various property replacements were handled via maintenance rather than via capitalization and retirement, the Company also deferred many replacements and/or upgrades for years beyond when such replacements were needed. This circumstance occurred from the Company's inability to obtain adequate rate relief in a timely manner. Keeping the existing plant in service for longer time periods resulted in larger reserve balances being accrued to the Company's books and records. Mr. Robinson testified that assuming the Company can obtain a fair rate of return and have sufficient access to cash, its construction program will continue at higher levels for the next several years, resulting in increased plant replacements and shorter service lives than experienced in the past.

Mr. Robinson attempted to refute Mr. McLawhorn's contention that the high level of the depreciation reserve was paid by ratepayers and hence refunds should immediately begin to be flowed back to ratepayers via the use of remaining life depreciation. Mr. Robinson testified that a review of pertinent information shows that much of the book versus theoretical accrued depreciation variance on the Company's books was not recovered from the Company's ratepayers. During the Company's most recent rate proceeding (1981 test year), $1,863,668 of depreciation expense was incorporated into revenue requirement. In the same case the Company's kWh sales used in its rate design and in support of its revenue requirement and resulting customer tariffs totaled 516,213,566 kWh. Thus depreciation expense is $0.00361 per kWh. Mr. Robinson calculated that since the rates have been in effect, the Company has accrued depreciation expense relative to retail customers totalling $29,698,143 to its books, or $7,590,581 more depreciation expense than the $22,107,562 collected through retail tariff rates.

Mr. Robinson gave reasons why it is inappropriate to use the average remaining life based depreciation rates for Nantahala in this case. The initial premise of utilizing average remaining life based depreciation rates is to recover a utility's unrecovered investment over the remaining life of the property with the goal of producing reasonably stable depreciation rates over time. He testified that it is clearly obvious that the current implementation of average remaining life based depreciation rates would produce an unacceptable reduction in the Company's level of depreciation rates and resulting depreciation expense.

The present implementation of average remaining life based depreciation rates would radically reduce current expense now, only to have higher depreciation rates later when larger portions of the Company's plant in service have been upgraded or replaced. Mr. Robinson cited as an example the depreciation rate for transportation equipment. Mr. McLawhorn is proposing a 0% depreciation rate for this account. Mr. Robinson testified that when the Company acquires additional property during the next several years, no depreciation expense would be accrued until a new depreciation study was completed. Such a study, completed several years after the property was placed in service, would result in a dramatic depreciation expense increase because there would be only a few years remaining in which to recover the full cost of the property. The impact would be wide fluctuations in depreciation rates between Mr. McLawhorn's presently proposed and the Company's next study resulting in measurable fluctuations in the Company's cost of service and in electric rates themselves. Rate stability is important to customers.

Mr. Robinson testified that the Company is currently in the process of completing a significant construction program over the period 1992 through 1996. During this period the Company anticipates spending approximately $75 million for additional plant in service. This construction program will result in a growth of the Company's plant in service of more than 75%. Likewise, during this process the Company will be retiring property being replaced by this new plant. These retirements and associated costs of removal will serve to reduce the level of the Company's book depreciation reserve as a percentage of utility plant in service. Mr. Robinson testified that a new depreciation study, completed around the 1996 time frame, will provide more applicable service life and salvage factors, and that would be a more appropriate time to assess the possible implementation of average remaining life, as well as other procedural changes to the Company's depreciation rates.

Mr. Robinson testified that if his depreciation rates are accepted, there will be a reduction of approximately $900,000 or 22% from current depreciation rates. Mr. McLawhorn's depreciation proposals, if adopted, would result in a further depreciation expense reduction of $680,802, or an overall reduction from current deprecation expense levels of more than 40% for the test year. This would harm the Company's ability to finance its significant ongoing construction program, plus it would be an imprudent short-term action with regard to the Company's depreciation rates. The result of this large reduction now would be an increase in depreciation rates in the future. In the end, both methods will arrive at the same place; the Company will not over-recover depreciation.

The Commission has analyzed in detail the testimony and exhibits relating to the issue of the appropriate depreciation technique. Based upon this analysis, the Commission determines that it should permit and require Nantahala to continue to rely upon the whole life depreciation technique at this time. Both witnesses Robinson and McLawhorn testified that both the whole life and the average remaining life techniques are appropriate and acceptable for use within the utility industry.

The Commission recognizes as meritorious Mr. McLawhorn's testimony that, in many circumstances, the average remaining life is useful in determining depreciation rates. Nantahala does not resist in principle conversion from the whole life to the average remaining life technique. However, Nantahala strongly advocates that the appropriate time for such a conversion is not in this case. The Commission agrees.

Nantahala, as a part of its application in this case, conducted, a comprehensive depreciation study. This study indicated that it would be appropriate to reduce depreciation rates by approximately 20%. A 20% reduction in depreciation expense is a substantial modification to make at one time, especially for a Company in the process of undertaking a substantial construction and upgrade program.

The Company is greatly concerned that any conversion would drastically reduce the Company's major source of internally generated funds at a time when these funds are crucially needed to finance the substantial construction program. The undisputed evidence in this case suggests that Nantahala will be spending $75 million between 1992 and 1996 on its system upgrade program. The Commission deems it highly inadvisable to limit the Company's primary source of internally generated funds in light of the minimal adverse consequences that exist from continuing the whole life technique.

As Mr. McLawhorn verified on cross-examination, conversion from the whole life to the average remaining life technique affects the timing of recovery of the costs of plant in service but does not affect the total amount of funds recovered by the Company through depreciation expense over time. The issue is simply one of timing. We find significant the Company's testimony describing past depreciation accounting practices prior to 1986/1987. Under the influence of accounting practices followed by its industrial parent, Alcoa, Nantahala apparently engaged in the practice of expensing plant replacements rather than retiring the plant replaced which practice resulted in a substantial imbalance in the depreciation reserve.

Although Mr. McLawhorn relies upon the fact that other utilities in this State use the average remaining life, he provided no testimony that conversion from one technique to another would have caused those companies such a substantial reduction in internally generated funds. Although he indicated that when Duke Power Company converted from whole life to average remaining life, there was a depreciation reserve imbalance that required correction, he testified that the imbalance for Duke was not nearly as great as the identified imbalance for Nantahala relative to the size of the two companies.

In deciding that Nantahala should continue to utilize the whole life technique, we are mindful of the fact that if we require adoption of remaining life for the Company at this time, the substantial reduction in depreciation rates that would be caused in this case will likely be reversed the next time there is a change in depreciation rates. With Nantahala's substantial construction program, the addition of substantial pieces of plant at high costs and the accelerated level of retirements of old plant, it is inescapable that any subsequent depreciation study will indicate that depreciation rates must be increased. In light of that fact, we deem it inadvisable to reduce rates to the substantial level recommended by Mr. McLawhorn at this time.

The Commission concludes that the appropriate level of depreciation expense to include in this proceeding is $3,813,761 which includes the adjustment to depreciation expense regarding storm damage costs with which both parties agree.

Charitable Contributions

The third area of difference between the Company and the Public Staff is charitable contributions. Public Staff witness Dietz testified that she removed all items specifically identified by the Company in its filing as charitable contributions. Ms. Dietz further testified,

> Contributions are not a necessary cost of providing utility service. Furthermore, ratepayers should not be required to pay for contributions to charities selected by the Company rather than the ratepayers.

Ms. Dietz also stated that her adjustment is consistent with the prior Commission decisions disallowing charitable contributions as operating revenue deductions.

Company witness Stonebraker testified in rebuttal that ratepayers benefit from and support the contributions made by the Company. He stated that the Company believes charitable contributions are a necessary part of being a good corporate citizen. Mr. Stonebraker concluded his rebuttal by stating that if the return on equity is not adequate, the Company will be forced to re-evaluate its level of contributions.

During cross-examination, Ms. Dietz stressed that the Commission has consistently ruled that charitable contributions should not be part of the cost of service. Ms. Dietz further testified that ratepayers should be allowed to donate to charities if they choose to do so, but they should not be forced to do so through their electric rates.

The Commission concludes that the Company's charitable contributions should not be included in the cost of service. It has been a long-standing policy of this Commission to exclude contributions from operating expenses. Charitable contributions are not a necessary cost of providing electric service. Given that fact, it would be unfair to require ratepayers to essentially make involuntary contributions to charities of the Company's choosing, especially when the vast majority of those ratepayers do not have the option of switching to another provider of electric service.

Therefore, the Commission concludes that the Public Staff adjustment to remove all charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

Income Taxes

The final area of difference between the Company and the Public Staff is income taxes. The parties have agreed that income tax expense should be reduced by excess deferred income taxes of $11,511. Therefore, the Commission concludes this adjustment is appropriate.

The difference of $418,173 between the levels of income taxes recommended by the Company and the Public Staff results from other Public Staff adjustments to expenses. Based on its findings elsewhere in this Order, the Commission concludes that the level of income tax expense under present rates appropriate for use in this proceeding is $1,089,681.

Based upon the conclusions in this Order, the Commission finds that the level of operating revenue deductions under present rates, excluding purchased power expense, appropriate for use in this proceeding is $19,437,739, calculated as follows:

Item	Amount
Operating and maintenance expense	$13,140,462
Depreciation expense	3,813,761
Taxes other than income taxes	1,374,636
Interest on customer deposits	19,199
Income taxes	1,089,681
Total operating revenue deductions	$19,437,739

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 59

There is no disagreement between the parties over the appropriate capital structure to be used for purposes of this proceeding. The Company proposed that the Commission employ Nantahala's actual capital structure at December 31, 1992. Public Staff witness Strickland agreed with the Company's proposal for purposes of this proceeding. However, he noted that said capital structure contained a higher common equity ratio and lower debt ratio than those of most publicly traded electric utilities. Therefore, witness Strickland recommended that in future proceedings the propriety of such a capital structure be revisited and carefully examined. Regarding the embedded cost of long-term debt, there is no disagreement between the parties over that cost rate.

The Commission, therefore, finds and concludes that the proper capital structure and the appropriate embedded cost of long-term debt to be used herein are as follows:

	Capitalization Ratio	Cost Rate
Long-term debt	43.89%	8.04%
Common equity	56.11%	-
Total	100.00%	-

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 60-66

The evidence in support of these findings of fact is contained in the testimony and exhibits of Nantahala witness Spann and Public Staff witness Strickland.

The Company and the Public Staff were not in agreement on the appropriate cost of common equity capital. Company witness Spann recommended a cost of common equity of 13.0%. Public Staff witness Strickland recommended that Nantahala be allowed the opportunity to earn 11.4% on common equity.

To arrive at his recommendation, witness Spann first determined that the cost of common equity to a typical energy utility was in the range of 11.8% to 12.55%. He reached that conclusion using two approaches. In the first approach, he reviewed this Commission's allowed returns on common equity in 29 electric and natural gas rate Orders during the period 1981 through 1991 and adjusted the returns to reflect current interest rates. The second approach employed two historical risk premium studies.

To his aforementioned 11.8% to 12.55% range, witness Spann added 50 basis points to adjust for the small size of Nantahala. This resulted in a cost of common equity range of 12.3% to 13.0%. He then recommended that the Commission adopt the upper-end of that range. Witness Spann made that recommendation because, in his opinion, a small utility such as Nantahala would tend to wait longer than a larger utility to file a rate case after its earned return has dropped below its cost of capital. Witness Spann attributed this phenomenon to Nantahala's limited staff resources, given the large commitment of human resources required to file a general rate case.

More specifically, in his first approach, witness Spann, after determining the differences between the returns on common equity allowed by this Commission in 29 gas and electric utility rate cases during the period 1981 through 1991 and the average Moody's AA utility bond rates for the six months prior to each Order, used this data, or part of this data, in two ways to arrive at cost of common equity estimates. First, witness Spann determined the average common equity risk premium from two sets of gas and electric Orders: (1) when interest rates were less than 10%, where the average premium was 3.78%, and (2) when interest rates were less than 9.3%, where the average premium was 3.93%. Adding the 3.78% and 3.93% premiums to the six-month average (September 1992 through February 1993) Moody's AA utility bond rate of 8.27%, he arrived at cost of common equity estimates of 12.05% and 12.20%. Second, he estimated a linear regression between the common equity premiums and the average Moody's AA bond rate using the data from all of the 29 gas and electric rate cases. Using this equation and the recent six-month average Moody's AA bond rate of 8.27%, he arrived at cost of common equity estimates of 12.33% for an electric utility and 12.75% for a gas utility.

In his second approach, witness Spann performed two separate historical risk premium studies. In the first study, the average annual returns for holding Moody's Electric Utility Stocks were compared to the annual returns for holding Moody's AA utility bonds during the period 1932 through 1990. This study resulted in a risk premium of 3.42%. In his second historical risk premium study, the average annual returns for holding S&P's 40 Utility Stocks were compared to the annual return for holding Moody's AA utility bonds during the period 1926 through 1991. This study resulted in a risk premium of 4.40%. When these two historical risk premiums were added to the average yield on Moody's AA utility bonds over the most recent six-month period, witness Spann obtained estimates of the cost of common equity of 11.69% and 12.67%.

Using the results of the two approaches, witness Spann concluded that the cost of common equity to an energy utility was in the range of 11.8% to 12.55%. However, he contended that two adjustments to said range were necessary due to the small size of Nantahala.

Witness Spann first adjusted the 11.8% to 12.55% range by adding 50 basis points to account for the size of Nantahala. This resulted in a cost of common equity range of 12.3% to 13.0%. Witness Spann testified that such an adjustment was necessary because the small size of Nantahala increased investment risk. According to his testimony, a number of academic studies indicate that the stocks of small publicly held firms tend to show higher returns than those found in larger firms. He surmised that those studies supported the necessity for an adjustment due to small size. He determined that the magnitude of 50 basis points was appropriate by measuring the difference in interest rates between the privately placed debt issues of small energy utilities, including Nantahala, and the publicly traded debt of utilities such as Duke, Carolina Power & Light Company (CP&L), and Virginia Electric and Power Company (VEPCO). Finally, as previously stated, witness Spann recommended that the Commission adopt the upper-end of the foregoing range. This recommendation, as previously indicated, was based on witness Spann's belief that a small utility such as Nantahala would tend to wait longer than a larger utility to file a rate case after its earned rate of return has dropped below its cost of capital due to its limited staff resources given the large commitment of human resources required to file a general rate case.

Public Staff witness Strickland used data from a risk premium study conducted by the staff of the Federal Energy Regulatory Commission (FERC) in determining his 11.4% cost of common equity capital. According to his testimony, the purpose of the FERC study was to quantify the risk premium investors require to invest in an electric utility's common equity instead of its bonds.

The FERC study compared the state-allowed common equity returns for electric utilities to each electric utility's bond costs in the six months prior to the decision. The bond costs in the FERC study were measured by the yield-to-maturity for each company's long-term 20 to 30-year bonds. The study included sample data from 354 rate cases over the period 1983 through mid-1992. This sample was constructed to exclude stipulated or settled cases. Witness Strickland's testimony showed that the average annual risk premiums ranged from a low of 1.79% to a high of 3.67% and averaged 2.78%. In more recent years, the average annual premiums have been approximately 2.80%.

Witness Strickland also performed a statistical regression to test the relationship of allowed equity premiums and bond costs. Using the estimated equation and the exact methodology used by the FERC staff to determine a representative bond cost for Nantahala, he arrived at an estimated risk premium of 3.60%. Considering both the average annual premiums and the regression estimated premium, witness Strickland concluded that the appropriate current risk premium was 2.80% to 3.60%. To determine the current representative bond costs, which he found to be 8.16%, witness Strickland used the same methodology employed in the FERC risk premium study. Additionally, he noted that the most recent six-month average rate of Moody's AA rated utility bonds, which was employed by Dr. Spann in each of his risk premium studies, was 8.27%. Witness Strickland testified that use of either approach would result in a reasonable and representative bond cost rate of approximately 8.20%. By adding the 2.80% to 3.60% risk premium range to the 8.20% bond cost rate, witness Strickland arrived at his recommended cost of equity range of 11.0% to 11.8%.

The determination of the fair rate of return for the Company is of great importance and must be made with care because the return allowed will have an immediate impact on the Company, its stockholder, and its customers. In the final analysis, the determination of a fair rate of return must be made by this Commission using its own impartial judgment and guided by the testimony of expert witnesses and other evidence of record. Whatever return is allowed, the Commission must balance the interests of Nantahala's ratepayers and its investor and meet the test set forth in G.S. 62-133(b)(4) to:

> "enable the public utility by sound management to produce a fair profit for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and its existing investors."

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b):

> "supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States."

<u>State ex rel. Utilities Commission</u> v. <u>Duke Power Co.,</u> 285 N.C. 377, 388, 206 S.E.2d 269, 276 (1974).

The Commission is mindful that its conclusion regarding the appropriate rate of return must be based upon specific findings showing what effect it gave to particular factors in reaching its decision. <u>State ex rel. Utilities Commission</u> v. <u>Public Staff,</u> 322 N.C. 689, 699, 370 S.E.2d 567, 573 (1988). Based on the entire evidence of record, the Commission concludes:

(1) <u>The overall methodology utilized by Company witness Spann, which incorporated data from his study of the authorized returns on common equity of 29 energy utilities regulated by this Commission, before consideration of his specific adjustment and recommendation related to the size of Nantahala, should</u>

be accorded the greatest weight in determining the cost of common equity for purposes of this proceeding. More specifically, his analyses under that methodology when (a) interest rates were less than 10% and when (b) interest rates were less than 9.3% should be accorded the greatest weight. The Commission's decision, to place the greatest weight on the aforesaid methodology is based primarily on the fact that witness Spann's testimony was far more persuasive than was the testimony of Public Staff witness Strickland relating to the propriety of use of the FERC staff methodology.

As previously stated, in applying the foregoing methodology, witness Spann obtained a list of the average returns on equity granted energy utilities by this Commission for the period 1981 through 1991 and a list of average Moody's AA utility bond rates for the six months prior to each Order. He then developed equity risk premiums by determining the differences between the allowed returns on equity and the Moody's AA bond rates. Analysis of the data so compiled indicates that, when interest rates are low, the difference between the equity return allowed by the Commission and contemporaneous interest rates is significantly higher than when interest rates are high.

Witness Spann determined from the data he analyzed that the average equity risk premium is 3.78% for Orders issued when interest rates are less than 10% and 3.93% for Orders issued when interest rates are less than 9.3%. When the current Moody's AA bond cost rate of 8.27% is added to the foregoing equity risk premiums, the indicated cost of common equity is in the range of 12.05% to 12.20%.

Both witness Spann and witness Strickland testified that as the cost of long-term debt decreases the equity risk premium increases. Current interest rates are at very low levels by the standards of recent history. In his analysis of the 29 Commission Orders, witness Spann placed greater emphasis on those Orders when long-term interest rates were low. The Commission agrees that it is appropriate to emphasize those Orders given the currently existing low level of interest rates.

As previously indicated, the 29 Orders selected for analysis by witness Spann included Orders relating to both electric and natural gas utilities. The Commission agrees with witness Spann that Nantahala has unique characteristics that, in some respects, make it dissimilar to the other electric utilities in the State and, in some respects, similar to the natural gas utilities within the State. The Commission therefore finds and concludes that witness Spann's inclusion of both electric and natural gas utilities in his study was reasonable and appropriate.

(2) The FERC staff risk premium study and approach as presented by Public Staff witness Strickland should be accorded only minimal weight for purposes of this proceeding. As previously stated, Public Staff witness Strickland employed the FERC staff risk premium approach in estimating the cost of common equity to Nantahala. Using that approach, he determined that a common equity risk premium of 2.80% to 3.60% was appropriate. By summing that premium range and his proposed current bond cost rate of 8.20%, witness Strickland derived his recommended cost of common equity range of 11.0% to 11.8%.

In at least one general rate case proceeding in the recent past, the Commission, in determining the cost of common equity, assigned a greater weight to the FERC staff risk premium methodology than to the other methodologies presented. (See the Commission's Order issued February 26, 1993, in Docket No. E-22, Subs 333 and 335, concerning North Carolina Power's requests for authority to adjust its electric rates and charges.) However, in this proceeding, the evidence presented by Company witness Spann in support of the methodology that the Commission has heretofore assigned the greater weight is much more persuasive than is the evidence offered by the Public Staff in support of the FERC staff methodology. Therefore, for purposes of this proceeding, the Commission has assigned only minimal weight to the FERC staff methodology. Before proceeding, however, the Commission wishes to emphasize that its decision in this regard is based solely on the evidence presented in this case and is not intended to herein impugn the efficacy of use of the FERC staff methodology in future proceedings.

(3) The Moody's Electric Utility Stocks and the S&P's 40 Utility Stocks historical risk premium studies presented by Company witness Spann should be accorded only minimal weight for purposes of this proceeding. As previously indicated, one of witness Spann's two historical risk premium studies estimated the risk premium as the difference between the average annual return on Moody's Electric Stocks and the yield on Moody's AA rated utility bonds over the period 1932 through 1990. Witness Spann's other historical risk premium study estimated the risk premium as the difference between the average annual return realized on S&P's 40 Utility Stocks and the yield on Moody's AA rated utility bonds over the period 1926 through 1991. The Commission, after careful consideration of the evidence presented, finds and concludes that these risk premium studies fail to appropriately consider that economic conditions during the periods studied were vastly different from the economic conditions of today. Additionally, the Commission notes that S&P's 40 Utility Stocks group includes gas pipeline companies, telephone companies, and other utilities not comparable in risk to Nantahala. Based on the foregoing and all other evidence of record, the Commission finds and concludes that the Moody's Electric Utility Stocks and the S&P's 40 Utility Stocks historical risk premium studies presented by Company witness Spann should be accorded only minimal weight for purposes of this proceeding.

(4) Company witness Spann's addition of 50 basis points to the cost of common equity determined from risk premium studies in recognition of the size of Nantahala is not appropriate for purposes of this proceeding. Witness Spann recommended adding 50 basis points to the cost of common equity derived from his risk premium studies because, in his view, a number of studies in the academic literature indicate that the stocks of very small publicly held firms tend to show higher returns than those found in larger firms. Therefore, witness Spann contended that there is greater risk associated with investment in small firms. On cross-examination, witness Spann defined a small company as one having less than one hundred million dollars of common equity.

Public Staff witness Strickland testified that witness Spann provided a list of four academic studies in response to a Public Staff data request which asked for citations for each academic study upon which he relied. All of these studies used as their data base either all stocks traded on the New York Stock Exchange or American Stock Exchange or a sample from those exchanges, but no study studied only regulated utilities.

Witness Strickland testified that, even if a study were to show small utilities earned returns higher than large firms, the difference could be attributable to factors other than size and relative risk. Witness Strickland pointed out that unlike many of the firms in the academic studies cited, as a regulated utility, Nantahala operates in a franchised environment with procedures in place to seek rate relief for cost increases and unusual circumstances that might occur. He stated that investors assess the business risk of a company by considering demand volatility, price volatility of the product, and the ability to adjust output prices for changes in input prices. Therefore, in his opinion, size should not affect the risk or allowed return on equity of Nantahala.

The Commission, after careful consideration of the entire evidence of record, finds and concludes that the evidence does not support an adjustment to the cost of common equity in recognition of the size of Nantahala. In reaching this conclusion, the Commission has relied principally upon the reasoning of the Public Staff.

In this regard, the Commission notes that, in determining the magnitude of his adjustment to the cost of common equity due to Nantahala's size, witness Spann compared the cost of recent issues of Nantahala debt to the cost of recent issues of the debt of CP&L, Duke, and VEPCO as well as to recent debt issues of other small energy utilities. From this comparison of debt costs, as previously stated, witness Spann recommended an adjustment of 50 basis points. Under cross-examination, he acknowledged that privately placed debt has a higher debt cost than publicly traded debt. Nantahala's debt is privately placed, while Duke, CP&L, and VEPCO have publicly traded issues of debt. Witness Spann also acknowledged that the debt issues which he compared consisted of senior serial notes to first mortgage bonds, unsecured serial notes, and first and second mortgage bonds, among others, which have different risks.

Witness Spann on cross-examination agreed that the debt issues he compared also had different call dates. To attempt to eliminate the effect of the term on the utilities' debt costs, witness Spann subtracted the rate on government bonds of similar maturity from the cost rate of the debt issue and compared the term adjusted rates. However, Public Staff Spann Cross-Examination Exhibit No. 2 clearly shows that the difference in yields between A rated and 30-year government bonds has varied over time; therefore, the term adjustment does not totally eliminate term differences. Public Staff Spann Cross-Examination Exhibit No. 3 shows that the difference in the cost of a long-term AA rated utility bond versus the cost of a long-term A rated utility bond is currently only 15 basis points. This 15 basis point difference is considerably less than the 50 basis point adjustment recommended by witness Spann. Finally, and perhaps most importantly, the Commission concludes that even if a valid comparison indisputably showed that one utility had a higher cost of debt than another utility, this difference simply cannot be transferred to the allowed return on common equity. Rather, the cost of common equity is an independent determination based on the perceived risk by common equity investors. Witness Spann's testimony under cross-examination affirms the Commission's conclusions in this regard.

(5) <u>No adjustment should be made to the cost of common equity due to witness Spann's contention that because of its size Nantahala waits longer to file a general rate increase request than does a larger utility.</u> Company witness Spann contended that the cost of common equity to a typical energy utility was in the range of 11.8% to 12.55%. He then adjusted this range by adding 50 basis points, supposedly to account for Nantahala's size, thereby deriving a cost of common equity for Nantahala in the range of 12.3% to 13.0%. Finally, he recommended that the cost of common equity for Nantahala be set at the upper-end of that range. He recommended that the upper-end of the range be employed because, in

his view, a small utility such as Nantahala would tend to wait longer than a larger utility to file a general rate case after its earned rate of return dropped below its cost of capital, due to the large commitment of resources that is required to file such a case. On cross-examination, witness Spann could not provide an indication as to how much longer Nantahala would wait to file a rate case due to its size, but he explained that Nantahala could stay out longer if it received a high enough return.

Public Staff witness Strickland contended that the subject adjustment was entirely inappropriate. He testified that, when witness Spann was asked in a Public Staff data request to explain how much longer Nantahala would wait to file a rate case than would a larger utility due to its size, witness Spann responded that "the amount of calendar time Nantahala would wait to file a rate case would depend on inflation, construction expenditures, and other factors that determine the rate at which Nantahala's earned rate of return is falling below its cost of capital." Witness Strickland contended that witness Spann's response failed to support or quantify his contention regarding the timing of filing of general rate increase requests by Nantahala. Witness Strickland further testified that the factors cited by witness Spann in the subject response are not unique to a utility the size of Nantahala. Witness Strickland also pointed out that if a higher return were allowed for this unsupported and unquantifiable contention, it would remain in effect until the Company's next rate case. Finally, witness Strickland noted that the Commission routinely provides for the recovery of reasonable rate case expenses in establishing a utility's cost of service or revenue requirement in general rate case proceedings. The Commission agrees with witness Strickland's views in this regard.

The Commission, after having very carefully considered the entire evidence of record, finds and concludes that Nantahala's contention that it is reasonable to increase the cost of common equity to Nantahala due to the timing of its filing of general rate increase requests is not supported by the evidence. Nantahala's management is responsible for requesting rate relief when needed in a timely manner. If it does so, the Company will be allowed every reasonable opportunity to recover its reasonable cost of service, including reasonable rate case expenses. The Commission can do no more.

(6) <u>The cost of common equity capital to Nantahala for purposes of this proceeding is 12.1%.</u> In reaching its decision in this regard, the Commission, as previously stated, has placed the greatest weight on a certain methodology employed by Company witness Spann. That decision is based primarily on the fact that witness Spann's testimony was far more persuasive than was the testimony of witness Strickland relating to the propriety of use of the FERC staff methodology. After having very carefully considered the entire evidence of record, the Commission finds and concludes that the cost of common equity to Nantahala for purposes of this proceeding is 12.1%. Such cost rate is well within the range of returns testified to by Company witness Spann before consideration of his proposals to make additional cost allowances in recognition of the size of Nantahala. As previously discussed, the Commission has rejected witness Spann's proposed allowances related to the size of Nantahala.

(7) <u>The overall fair rate of return which the Company should be allowed the opportunity to earn on its rate base is 10.32%.</u> Based on the Commission's findings with respect to the proper capital structure and the appropriate cost rates for each component of capital reflected in the capital structure, the

Commission finds and concludes that the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 10.32%.

It is well-settled law in this State that it is for the administrative body in an adjudicatory proceeding to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts, and to appraise conflicting evidence. State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E.2d 786 (1982); Commissioner of Insurance v. North Carolina Rate Bureau, 300 N.C. 381, 269 S.E.2d 547 (1980). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not res judicata in succeeding cases. State ex rel. Utilities Commission v. Duke Power Company, 285 N.C. 377, 395, 206 S.E.2d 269, 281 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations that vary from case to case." State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 697, 370 S.E.2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented and its weight and credibility in each case.

The Commission cannot guarantee that Nantahala, in fact, will achieve the levels of return on rate base and common equity found to be just and reasonable herein. Indeed, the Commission would not guarantee the authorized rates of return even if it could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds and concludes that the rates of return approved in this Order will afford the Company a reasonable opportunity to earn a reasonable return for its stockholder while providing adequate and economical service to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 67

The Commission has previously discussed its findings and conclusions regarding the fair rates of return on rate base and common equity which the Company should be afforded an opportunity to earn.

The following schedules summarize the gross revenue (excluding purchased power revenue) and the rates of return on rate base and common equity which the Company should have a reasonable opportunity to achieve based upon the Commission's decision in this case. These schedules, illustrating the Company's gross revenue requirement (excluding purchased power revenue), incorporate the findings and conclusions made by the Commission. As reflected in Schedule I, the Company should be authorized to increase its annual level of non-purchased power revenue by $4,333,980 based upon the adjusted test year level of operations.

SCHEDULE I
NANTAHALA POWER AND LIGHT COMPANY
North Carolina Retail Operations
Docket No. E-13, Sub 157
STATEMENT OF OPERATING INCOME
Twelve Months Ended December 31, 1991

Item	Present Rates	Approved Increase	Approved Rates
Operating revenue	$23,972,903	$4,333,980	$28,306,883
Operating revenue deductions:			
Operation and maintenance expense	13,140,462	18,407	13,158,869
Depreciation expense	3,813,761	0	3,813,761
Taxes other than income taxes	1,374,636	139,081	1,513,717
Interest on customer deposits	19,199	0	19,199
Income taxes	1,089,681	1,635,774	2,725,455
Total operating revenue deductions	19,437,739	1,793,262	21,231,001
Net operating income	$4,535,164	$2,540,718	$ 7,075,882

SCHEDULE II
NANTAHALA POWER AND LIGHT COMPANY
North Carolina Retail Operations
Docket No. E-13, Sub 157
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1991

Item	Amount
Electric plant in service	$131,964,517
Accumulated provision for depreciation	(63,824,525)
Net electric plant in service	68,139,992
Materials and supplies	2,045,942
Cash working capital	2,684,430
Deferred debits	6,993,128
Deferred credits	(658,280)
Customer deposits	(343,737)
Accumulated deferred income taxes	(9,769,719)
Other cost-free capital	(515,215)
Total original cost rate base	$ 68,576,541
Rates of return:	
Present rates	6.61%
Approved rates	10.32%

SCHEDULE III
NANTAHALA POWER AND LIGHT COMPANY
North Carolina Retail Operations
Docket No. E-13, Sub 157
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1991

Item	Capitalization Ratio %	Rate base	Embedded Cost Rates	Net Operating Income
	Present Rates - Rate Base			
Long-term debt	43.8861%	$ 30,095,569	8.040%	$2,419,684
Common equity	56.1139%	38,480,972	5.497%	2,115,480
Total	100.0000%	$ 68,576,541		$4,535,164
	Approved Rates - Rate Base			
Long-term debt	43.8861%	$30,095,569	8.040%	$2,419,684
Common equity	56.1139%	38,480,972	12.10%	4,656,198
Total	100.0000%	$68,576,541		$7,075,882

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 68

The evidence for this finding of fact is found in the testimony of Company witness Stonebraker and Public Staff witness Dietz. The Company has proposed that the Commission reconsider its decision in Docket No. E-13, Sub 142 to not allow Nantahala to collect interest from customers on undercollections of purchased power costs.

Public Staff witness Dietz testified that she believed the Commission had settled this issue with its ruling in Docket No. E-13, Sub 142. Ms. Dietz stated that the Commission, in the Sub 142 case, determined that Nantahala should not collect interest from ratepayers on undercollections of purchased power. The Commission also stated that such treatment would ensure consistent regulatory treatment between Nantahala and other electric utilities.

Company witness Stonebraker testified that the Commission's ruling that Nantahala must pay customers interest on overcollections of purchased power costs but cannot collect interest from customers on undercollections is neither fair nor equitable. Mr. Stonebraker also testified that Nantahala is being treated like other electric companies despite the fact that, with respect to purchased power costs, Nantahala is more like a gas company. Mr. Stonebraker further testified that interest goes both ways for gas companies when looking at over and undercollections of gas costs. In his rebuttal testimony, Mr. Stonebraker stated that the Company should not be forced to suffer a financial loss if customers' usage exceeds expectations.

The Commission concludes that its decision in Docket No. E-13, Sub 142 continues to be appropriate, and Nantahala should not be permitted to collect interest from ratepayers on undercollections of purchased power costs. In Sub 142, the Commission stated as follows:

This methodology is superior to Nantahala's proposal in that interest due ratepayers will always be provided on net overcollections. Interest will not accrue in favor of Nantahala if a net undercollection exists at the end of the test period. Nantahala should calculate interest on net overcollections utilizing an interest rate of 10% per annum. Adoption of this methodology for application to Nantahala will ensure a consistent regulatory treatment for the accrual of interest on net overcollections for Duke Power Company, Carolina Power & Light Company, North Carolina Power, and Nantahala.

The decision in Sub 142 was made after careful consideration of all of the evidence. No new evidence has been presented in this proceeding which convinces or compels the Commission to believe a different ruling is appropriate at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69

In his testimony in this docket, Public Staff witness McLawhorn requested that the Commission require Nantahala to conduct and file with the Commission a depreciation study at least once every five years. Mr. McLawhorn testified that he is asking the Commission to order Nantahala to begin preparing and submitting depreciation studies, including full life analysis, at least once every five years. He stated that this schedule is not unusual among utilities subject to the Commission's jurisdiction. Natural gas utilities are required to file depreciation studies every five years, and the telephone utilities that are subject to Federal Communications Commission's oversight file studies every three years.

In its proposed order, the Company resisted being required to file depreciation studies at five year intervals. It is the Company's position that no similar requirement exists for the other electric utilities in the State and that Nantahala should not be required to comply with a schedule more stringent than that imposed upon the other utilities.

The Commission determines that it should reject the request by the Public Staff for Nantahala to prepare and submit a depreciation study at least once every five years. The study presented by Nantahala in this case was conducted by the Company on its own behalf. The Company was not prodded to conduct the study by the Commission or the Public Staff. There is no indication that the Company has sought to avoid conducting a depreciation study so there is no need for the Commission to order the Company to perform such studies on a regular basis. Nantahala's consultant has recommended that depreciation studies be conducted on a regular basis. The Company has indicated a willingness to conduct such studies on a regular basis as needed. We find nothing in the record of this case suggesting that a Commission-imposed schedule is necessary or justified. The Commission therefore determines that the request that Nantahala conduct a study once every five years should be denied.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

Public Staff witness McLawhorn is his direct testimony recommended that Nantahala maintain depreciation rates on an individual account basis rather than on a functional group level basis. Company witness Robinson in his rebuttal testimony testified that Nantahala had maintained its depreciation rates on at least an individual account basis for a number of years. Mr. McLawhorn stated on cross-examination that he had perhaps incorrectly assumed that Nantahala had maintained depreciation rates with less detail than in fact occurs.

Based upon an analysis of the record, the Commission determines that it is unnecessary to impose a requirement upon Nantahala such as that suggested by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 71 - 73

Nantahala proposed the following increases for each customer class:

Residential	-	1.24 times overall increase
Small General Service	-	0.68 times overall increase
Large General Service	-	0.65 times overall increase
Yard Lighting	-	0.95 times overall increase
Street Lighting	-	1.01 times overall increase

The Public Staff proposed the following increases for each customer class:

Residential	-	1.36 times overall increase
Small General Service	-	0.32 times overall increase
Large General Service	-	0.71 times overall increase
Yard Lighting	-	0.00 times overall increase
Street Lighting	-	0.00 times overall increase

Nantahala's proposed customer class increases would be applied to Nantahala's proposed 12.5% overall increase, whereas the Public Staff's proposed customer class increases would be applied to the Public Staff's proposed 6.2% overall increase.

The current rates of return for each customer class, based on the Public Staff's cost-of-service study, are:

Residential	-	4.19%
Small General Service	-	15.94%
Large General Service	-	12.29%
Yard Lighting	-	65.40%
Street Lighting	-	21.38%

The rates of return resulting from the increases proposed by the parties for each customer class do not come close to being within 10 percent of the overall rate of return. Nevertheless, the increases proposed by the parties do move the rates of return for each customer class closer to being within 10 percent of the overall rate of return.

The Commission is of the opinion that the lighting classes should not be increased in view of the large rates of return already resulting from current rates. The small general service rates should not be increased as much as the large general service rates, and all major classes should be increased by approximately the average of the increase multipliers proposed by the parties for each class. Therefore, the Commission concludes that the individual customer classes should be increased as follows:

Residential	-	1.29 times overall increase
Small General Service	-	0.55 times overall increase
Large General Service	-	0.7 times overall increase
Yard Lighting	-	0.0 times overall increase
Street Lighting	-	0.0 times overall increase

Public Staff witness Turner recommended that the customer growth and weather normalization adjustments to kWh sales and revenues be used in calculating the customer class revenue targets herein. He also recommended that customer class revenue calculations should be rounded down where necessary to produce the overall revenue target approved herein so that the revenues produced by the rates do not exceed the overall revenue requirement. Witness Turner pointed out that Nantahala had not followed these two techniques in designing its proposed rates.

Nantahala witness Tucker stated that the Company does not object to the two recommendations. Therefore, the Commission concludes that the two recommendations by the Public Staff should be adopted herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 74

The testimony and exhibits relied upon in making this finding of fact are contained in the testimony and exhibits of Company witnesses Spann and Tucker and Public Staff witness Turner.

Company witness Spann testified that it is appropriate to use a minimum monthly bill provision of $14 in the residential rate schedule. He stated that the cost-of-service study he conducted indicated that Nantahala's customer costs are substantially in excess of the proposed $6 monthly customer charge. Nantahala has a large number of summer homes in its service territory. For the year 1991 as a whole, approximately 10 percent of all the residential bills sent out by Nantahala were for zero usage. Almost 20 percent of the total residential bills sent out by Nantahala in 1991 were for 100 kWh or less. An analysis of the zero usage bills by Nantahala indicates that two-thirds of the zero usage bills are mailed to zip codes outside of the service territory of the utility.

Witness Spann testified that maintaining the customer charge below customer costs forces Nantahala's year-round customers to subsidize second home owners. At the same time, an increase in the customer charge to the full level of customer costs indicated by the cost-of-service study would lead to overly large bill impacts on low usage year-round customers. He testified that the minimum bill combined with the current customer charge has the effect of requiring second home owners to pay an amount that approaches the customer costs they impose on Nantahala while not burdening lower usage, year-round customers with overly large rate increases.

Witness Turner from the Public Staff testified that the $14 minimum bill provision is designed to ensure that the costs of billing are always recovered. Witness Turner said that, based on the cost-of-service study, a customer charge of $14.56 per month can be supported. The impact, however, will be felt by all low use customers (those with primary residences inside as well as those with primary residences outside of the service area) and will result in all customers with low usage receiving large bill increases based on the proposed rate design.

Witness Turner testified that the Company's bill frequency analysis shows approximately 18 percent of Nantahala's residential bills will receive an increase of approximately 30 percent, about 15 percent of the residential bills will increase by more than 75 percent, and over 11 percent of the bills will receive a 145 percent increase. He testified that approximately 20 percent of the Company's total 510,450 residential bills will be impacted by the proposed minimum bill provision. He said approximately 40 percent of the 20 percent have primary residences inside the Company's service area and approximately 60 percent of the 20 percent are billed outside the Company's service area. He said that while the Public Staff supports cost-based rates, in this case the Public Staff believes that the magnitude of the increase should be reduced in view of the percentage increase. He said a minimum bill charge of $10 would still provide meaningful movement toward actual costs.

Witness Tucker testified on rebuttal that the increase of 145 percent referred to by witness Turner is based upon an increase in bills for customers with monthly usage of 10 kWh from $5.75 per month to $14 per month, an increase of $8.23 per month. He pointed out that within the 11 percent of customer bills mentioned by witness Turner, over 9 percent of the total bills had no usage. Witness Tucker said these customers are being subsidized by other customers at present, and any reduction in the proposed minimum bill will require other customers to continue this subsidization. He said that any actual increase on an extremely low bill will result in large percentage increases. The problem is not that the proposed $14 is too high but rather that the current bill is much too low.

The Commission has carefully considered this issue and concludes that the $14 minimum charge proposed by the Company is appropriate. There are a large number of seasonal customers served on the Nantahala system. Seasonal or part-time customers typically have low or zero usage for several months, and current billings for that level of service are currently inadequate.

The proposed minimum bill provision would have no impact if a customer uses about 125 kWh per month. There are few "permanent residences" that would be impacted by bills rendered for usage at this low level. Many of the low use bills rendered inside the Company's service area are seasonal customers; for example, condominium bills rendered to a central payment agent such as the Sapphire Valley complex, or bills to owners of rental units. Some are for water pumps or outbuildings separate from residences that were placed on separate meters because of the difficulty or expense of serving the remote facilities through the home meter. In all cases, Nantahala has incurred costs of building electric supply facilities to the location, and the costs of reading meters, issuing bills, and collecting payment each month as a result of the customer's choice of how his facilities are installed and utilized.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 75

Public Staff witness Turner recommended that the Commission require Nantahala to create an additional large general service rate for customers with demands less than 1,000 kW per month. He said that the rate schedule proposed by Nantahala for the large general service customer class does not differentiate between customers with demands less than 1,000 kW per month and those greater than 1,000 kW per month, yet the cost of service study results show a significant difference in cost.

Witness Turner testified that the rate of return index is over 1.5 times greater for the less than 1,000 kW group than the rate of return index for the over 1,000 kW group. He concluded that, based on these significant cost differences, a rate schedule designed for customers with demands less than 1,000 kW per month should be priced to reduce the rate of return index differential shown in the cost-of-service study by as much as practical, and that the Company's proposed large general service rate schedule should be available only for customers with demands greater than 1,000 kW per month.

Nantahala witness Tucker testified on rebuttal that applicability of the current large general service schedule should be studied, but that Nantahala does not agree that a new large general service rate schedule should be created for customers with demands of less than 1,000 kW. Witness Tucker testified that the break point of 1,000 kW is somewhat arbitrary and was originally developed for reporting in the FERC Form 1. That report requests a breakdown of "commercial" and "industrial" sales. Nantahala does not have an "industrial" class and used the billings for customers larger than 1,000 kW as "industrial sales" for that report.

Witness Tucker testified that review of the large general service schedule shows that seven of the eight customers with demands in excess of 1,000 kW are manufacturing concerns. The eighth is Western Carolina University. WCU does not have the same usage characteristics as the large manufacturing plants. Also, there are several manufacturing concerns that are served on the large general service rate schedule, but have demands of less than 1,000 kW. Witness Tucker said that there are differences in usage characteristics between smaller manufacturing concerns and commercial enterprises with similar peak demands. A department store, school, motel or supermarket does not have the same electric use characteristics as a plastic modeling operation, an electric cord manufacturing plant, a machine or cabinet shop, or a plant that bends and assembles piping for various automotive applications.

Witness Tucker stated that the cost difference that exists in the current large general service rate schedule results largely from customer type, i.e., commercial versus manufacturing, rather than from size.

After having examined this testimony, the Commission concludes that it would be appropriate to develop an "industrial" rate schedule applicable to only the manufacturing concerns that are classified within the Standard Industrial Classification. The Commission recognizes that size of load is also a factor that affects the cost of service. As a result, the "industrial" rate schedule should include a minimum demand for customer qualification for service under the schedule. Such minimum demand may be greater than or less than 1,000 kW. The "industrial" rate schedule should be initially designed to track the large General Service rate schedule. Cost data is not yet available for more accurate rate design of industrial rates and a significant change in design could result in rates to individual customers that are above noticed rates. Developing the new "industrial" rate schedule along these guidelines will allow cost data to be collected for that class to support rate design changes in the future, if necessary.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 76

Company witness Stonebraker requested permission to change the formula used in the levelized purchase power calculations. He proposed to exclude all purchased power expense from base rates. He said that Rider CP should be used to recover all purchased power costs, not just those costs in excess of the amount recovered in base rates. This procedure would not change the total rates charged to customers but does simplify the calculation, make review easier and enhance customer understanding. When the Company publishes its rate schedules annually, the rates shown will include the Rider CP amount. This will make it easier for customers to compute their bills.

The Public Staff did not take issue with this proposed change. Based on the above, the Commission determines that the change in the formula requested by the Company should be approved.

The Commission notes that the new base rates established herein will be for service rendered on and after the date of this Order while the new purchased power recovery factor established herein will be for bills rendered on or after June 27, 1993. Thus, the first bills rendered after the date of this Order will apply primarily to the current base rates, which contain $0.01132757 per kWh purchased power costs. However, the same first bills rendered after the date of this Order will also apply to the new purchased power recovery factor of $0.0287 per kWh established herein, and the new $0.0287 per kWh purchased power recovery factor will also include the $0.01132757 per kWh that was formerly contained in base rates. Therefore, it will be necessary for Nantahala to adjust the first bills rendered after the date of this Order so that customers will not be charged twice for the $0.01132757 per kWh purchased power costs described herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 77

The evidence for this finding of fact is found in the testimony of Public Staff witness Turner and Company witness Tucker.

Nantahala's service regulations dealing with residential electric line extensions, Paragraph 2(g), provide that the Company will extend electric facilities to the customer without cost except that the customer will be required to obtain necessary rights-of-way on the property of the customer or others without cost to the Company. The paragraph further states that the Company will assist in obtaining rights-of-way but that the obligation to provide rights-of-way remains the customer's responsibility.

Public Staff witness Turner recommended that this provision be changed. Mr. Turner expressed the opinion that this provision unduly burdens the customer and could result in the customer being denied access to electric service. Mr. Turner stated that the customer should be obligated to provide the Company access or the necessary right-of-way across his property, but to place the burden on the customer for securing a right-of-way across his neighbor's property is inappropriate. Mr. Turner expressed the opinion that if the customer's neighbor is unwilling to grant the right-of-way, the customer would be left without electric service and with no legal remedy to require the neighbor to provide the needed right-of-way. He stated that the Company, on the other hand, has a legal remedy, if needed, through eminent domain. This power has been wisely given to the State's public utilities to allow them to provide electric service in their assigned service areas to all customers.

Mr. Turner cited the complaint cases of James Bridgeman, Docket No. E-13, Sub 154, and Carl and Eleanor Tucker, Docket No. E-7, Sub 483. In the Bridgeman complaint, the customer could not get electric service because his neighbors were unwilling to allow the Company's lines to cross their property. Mr. Bridgeman requested electric service when he began construction of his house yet still had no service when the house was completed. It was not until Mr. Bridgeman brought his complaint before the Commission that he was finally able to receive service. The Tucker complaint was a case where the prospective customer was landlocked and the owners of neighboring property refused to convey a right-of-way. The Commission required Duke Power Company to proceed with condemnation to secure the needed rights-of-way.

Nantahala witness Tucker testified that the Company does not agree with Mr. Turner's recommendation. The language in the rules and regulations has served Nantahala and its customers well. In his opinion, a modification to that language would be unfair and would increase the cost of service to all customers. Mr. Tucker testified that the Company worked out an underground right-of-way in the Bridgeman complaint, but Mr. Bridgeman refused to pay the cost differential between the standard overhead and underground service. Through continuing efforts, the Company was ultimately able to work out an arrangement with another customer to provide Mr. Bridgeman with overhead service. Mr. Tucker accepted that the Commission ordered Duke to condemn a right-of-way to provide service in the Tucker complaint. He testified that if a customer requested service from Nantahala and was unable to obtain the necessary rights-of-way for electric lines, he could file a complaint with the Commission and seek relief.

The Commission finds no good cause for changing Nantahala's rules and regulations pertaining to rights-of-way. The present provisions are of long standing and have served the Company well. The Commission is not aware of any customer that has been unable to obtain service under the existing rules and regulations, and the Commission finds no good cause to change them. As acknowledged by the Company, customers have the option of filing a complaint if they feel circumstances warrant it.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 78

The evidence for this finding of fact is found in the testimony and exhibits of Company witnesses Spann and Tucker and was not contested by any party of record. The Commission finds the rate designs, rate schedules, miscellaneous charges, and terms and conditions of service proposed by the Company are reasonable and appropriate for use in this proceeding, except as specifically modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

On May 21, 1993, consistent with the Commission's Order of October 19, 1989, in Docket No. E-13, Sub 142, Nantahala filed a letter with supporting work papers showing the Company's estimated levelized purchased power recovery factor for the period June 1993 through March 1994 and its calculation of the net over (under) recovery for the period April 1992 through May 1993 with May 1993 costs estimated.

Also consistent with the Order of October 19, 1989, Nantahala filed on June 9, 1993, a letter with supporting workpapers showing the revised purchased power recovery factor based on the actual cost data for May 1993. The purchased power recovery factor requested by the Company is $0.0287 per kWh. This factor includes $0.0310 (including gross receipts tax) to recover estimated purchased power including the TVA/Ratchet for the 10 month period ending March 31, 1994, and a reduction of $0.0023 (including gross receipts tax) for the over-recovery during the preceding 14-month period.

The Commission concludes that the purchased power recovery factor requested by the Company is appropriate and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That Nantahala Power and Light Company is hereby authorized to adjust its electric rates and charges effective for service rendered on and after the date of this Order to produce an increase in gross annual revenues, excluding purchased power revenue, from its North Carolina retail operations of $4,333,980 based upon the adjusted test year level of operations.

2. That within five (5) working days after the date of this Order, the Company shall file with the Commission five copies of its rate schedules and service regulations designed to produce the increase in revenues adopted herein in accordance with the rate design guidelines attached hereto as Appendix A. These rate schedules shall be accompanied by computations showing the level of revenues which will be produced by the rates for each rate schedule.

3. That the Company shall give appropriate notice of the approved rate increase by mailing a notice to each of its North Carolina retail customers during the next normal billing cycle following the filing and approval of the rate schedules described herein. The Company shall submit its proposed customer notice to the Commission for approval before it is mailed to the customers.

4. That the Company shall conduct a study to determine the economic feasibility of conducting load research to determine the Company's customer class demands at the time of the system winter and summer peak demands. The study shall be filed with the Commission and the Public Staff within six (6) months after the date of this Order.

5. That the Company shall conduct a study to determine the appropriate portions of the capacity-related and customer-related distribution plant costs. The study shall be used in the Company's next cost-of-service study filed in connection with its next general rate case.

6. That the Company shall conduct a study to determine line losses by customer class. The study results shall be used in the Company's cost-of-service study filed in connection with its next general rate case.

7. That the rate design, rate schedules, miscellaneous charges, and terms and conditions of service proposed by the Company are approved for use in this proceeding, except as specifically modified herein.

8. That the Company shall design a separate rate schedule for industrial customers served under the Company's current large general service rate schedule based on the Standard Industrial Classification for those customers. For purposes of this proceeding, the industrial rate schedule shall initially be designed to track with the Large General Service rate schedule proposed by Nantahala herein.

9. That Nantahala shall defer those revenues associated with the "wheeling" transactions between Duke Power Company and TVA beginning on and after the date of this Order pending further determination of this matter in its next general rate case proceeding as more particularly set forth in this Order. Further, the parties to this proceeding are requested to investigate the feasibility and

appropriateness of the inclusion or tracking of these revenues in the context of the Company's purchased power adjustment proceeding and further address this issue in Nantahala's next general rate case proceeding.

10. That Nantahala shall defer any costs incurred relating to its conservation education program, as more particularly set forth herein, in excess of those which reference both safety and conservation information which has been included in the cost of service in this proceeding.

11. That Nantahala is hereby authorized to revise the formula used in calculating purchased power adjustments so that all purchased power expense is excluded from base rates and included in Rider CP. Consistent with the transfer of all purchased power expenses from base rates to Rider CP herein, Nantahala shall make the adjustments necessary to the first bills rendered after the date of this Order so that customers will not be charged twice for the $0.01132757 per kWh purchased power expense contained in the previous base rates, as described elsewhere herein.

12. That the purchased power recovery factor of $0.0287 per kWh (including gross receipts tax) as proposed by Nantahala for bills rendered on and after June 27, 1993, and expiring on April 25, 1994, is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

NANTAHALA POWER AND LIGHT COMPANY
DOCKET NO. E-13, SUB 157
Guidelines for Design of Rate Schedules

(A) Set the Residential minimum bill at $14.00 per month.

(B) Hold the extra charges and miscellaneous service charges at the same levels proposed by the Company.

(C) Distribute the rate schedule revenue increases in accordance with the following rate of increase multipliers:

Residential	1.29	times overall increase
Small General Service	0.55	"
Large General Service	0.70	"
Yard Lighting	0.00	"
Street Lighting	0.00	"
Overall	1.00	"

(D) Customer growth and weather normalization adjustment revenues (as shown by Revised Supplemental Exhibit BRT-2, Page 1 of 1) shall be used in determining rate schedule revenue targets.

(E) Maintain the relative price levels proposed for each rate schedule consistent with the overall rates of increase approved herein, except as specifically revised herein.

(F) Round off individual prices to the extent necessary for administrative efficiency, provided said rounded-off prices do not produce revenues which exceed the overall revenue requirement established by the Commission in this proceeding.

DOCKET NO. E-13, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Nantahala Power and Light Company-	)	ORDER APPROVING
Request For Approval of Accounting	)	ACCOUNTING TREATMENT
Treatment	)	

BY THE COMMISSION: On November 23, 1992, Nantahala Power and Light Company (Nantahala) filed a request with the Commission seeking approval of accounting treatment that will allow deferral of extraordinary costs and amortization of such costs over ten years, beginning in 1992 and 1993.

The costs for which Nantahala seeks such deferral accounting treatment are:

1. $490,000 for the painting of (a) the penstock and surge tank at the Nantahala plant, (b) the penstocks for Dicks Creek and White Oak diversions, (c) the Thorpe penstock and (d) the Tennessee Creek penstock.

2. $1,700,000 for expenditures in excess of the original $500,000 estimate relating to dam repairs at the Franklin Hydro Plant.

3. $426,000 for cleanup of contaminated soil at certain substations and storage locations.

The Company stated that due to the relatively large amount involved with respect to these projects, it determined that Commission approval for deferral accounting should be sought for these items.

In support of its proposal, Nantahala states as follows:

(1) Nantahala considers each of these expenditures as extraordinary and non-recurring. The Company's position is that the Company's books of accounts will provide a distorted picture if these items are expensed on the books when incurred.

(2) Financial statements should reflect a normal level of expense. Nantahala's proposal is to set the normal level of these costs and to account for them in a manner consistent with anticipated ratemaking treatment in accordance with SFAS 71.

(3) If the accounting treatment of these costs differs from the ratemaking treatment, Nantahala's financial statements would be misleading.

(4) In Docket No. E-13, Sub 35, the Commission approved deferral of extraordinary maintenance costs.

(5) In Docket No. E-13, Sub 136, the Commission approved similar deferred accounting for $698,000 relating to the rewind of the Nantahala generator.

(6) Deferral accounting was also authorized for an estimated $500,000 expenditure to repair the surface of the dam and spillway and replace the seal plate of the tainter gate of Nantahala's Franklin Hydro Plant. Due to additional costs involving the project, the final cost of this project totals $2,200,000, an increase of $1,700,000 over the original estimate of $500,000.

On January 6, 1993, the Public Staff filed a response to the request by Nantahala. In its response, the Public Staff recommended that the Commission approve Nantahala's requested accounting treatment for the additional costs associated with the dam repairs at the Franklin Hydro Plant and the cleanup costs, without prejudice to the right of any party to take issue with such accounting treatment in a regulatory proceeding.

Further, the Public Staff recommended that the Commission deny the request of Nantahala to defer certain painting costs. Although the ratemaking treatment of these costs may be considered in determining a representative level of expenses in the Company's pending general rate case, there is no justification for any special accounting treatment for painting costs, which are not extraordinary in nature. According to the Public Staff, this approach is consistent with the Commission's finding in Docket No. E-13, Sub 136, in which the Commission determined that costs such as painting should not be granted capital or deferred treatment, but should be considered as maintenance expense applicable to the period in which they were actually incurred.

On January 8, 1993, Nantahala filed a response to the filing by the Public Staff.

Based on the foregoing and the record in this matter, the Commission concludes that the additional expenditures for dam repairs at the Franklin Hydro Plant should be deferred and amortized over a period of ten years. Such treatment is consistent with the treatment afforded the original $500,000 estimate in the Commission's Order in Docket No. E-13, Sub 136, dated December 12, 1989. Further, the Commission concludes that the costs of cleanup of contaminated soil at certain substations and storage locations should likewise be deferred and amortized over a period of ten years. In so concluding, the Commission is convinced that these are extraordinary expenditures of such magnitude as to warrant deferral accounting treatment. Further, the Commission is of the opinion that these are expenditures which do not occur regularly and are of a nature similar to those for which the Commission has approved deferral and amortization treatment in the past.

With respect to the aforesaid painting costs, the Commission likewise concludes for similar reasons that such expenditures should be deferred and amortized over a period of ten years. The Public Staff, in its response, pointed to the Commission's decision in Docket No. E-13, Sub 136, in which the Commission determined that certain painting costs should not be granted capital or deferred treatment, but should be considered as maintenance expense applicable to the period in which they were actually incurred.

At issue in the Commission's decision in Docket No. E-13, Sub 136, were expenditures in the amount of $74,832 for painting of the Queens Creek Hydro pipeline. As also pointed out in its Order, the Commission was of the opinion that such costs, although significant in amount and infrequently occurring, were not of such magnitude as to warrant deferral accounting treatment. This is certainly not the situation with respect to the painting costs at issue herein.

The accounting treatment authorized herein is without prejudice to the right of any party to take issue with such accounting treatment in the context of a general rate case proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the request by Nantahala Power and Light Company for accounting treatment that will allow deferral of certain extraordinary costs and amortization of such costs over ten years beginning in 1992 and 1993, is hereby approved consistent with the provisions of this Order.

2. That the accounting treatment authorized herein is without prejudice to the right of any party to take issue with such accounting treatment in the context of a general rate case proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of January 1992.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-22, SUB 333
DOCKET NO. E-22, SUB 335

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request of North Carolina Power for Authority to Adjust Its Electric Rates and Charges and Application of North Carolina Power Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	ORDER GRANTING PARTIAL RATE INCREASE

ELECTRICITY - RATES

HEARD: Wednesday, January 6, 1993, at 7:00 p.m., Council Chambers, Town Hall, 201 West Main Street, Ahoskie, North Carolina

Wednesday, January 6, 1993, at 7:00 p.m., Courtroom B, Pasquotank County Courthouse, Elizabeth City, North Carolina

Thursday, January 7, 1993, at 7:00 p.m., Assembly Room, City Hall, Main Street, Williamston, North Carolina

Thursday, January 7, 1993, at 7:00 p.m., Kirkwood F. Adams Community Center, 1100 Hamilton Street, Roanoke Rapids, North Carolina

Tuesday, January 12, 1993, at 9:30 a.m., through Friday, January 15, 1993, and Tuesday, January 19, 1993, through Wednesday, January 20, 1993, in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman William W. Redman Jr., Presiding; Commissioners Sarah Lindsay Tate, Julius A. Wright, Robert O. Wells, Charles H. Hughes, Laurence A. Cobb, and Allyson K. Duncan

APPEARANCES:

For North Carolina Power:

Edgar M. Roach, Jr., Edward S. Finley Jr., and Frank A. Schiller, Hunton and Williams, Attorneys at Law, Post Office Box 109, Raleigh, North Carolina 27602

and

James S. Copenhaver, Senior Regulatory Counsel, North Carolina Power, Post Office Box 26666, Richmond, Virginia 23261

For the Public Staff:

A. W. Turner, Jr., Robert B. Cauthen, Jr., and Gisele L. Rankin, Staff Attorneys, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Jo Anne Sanford, Special Deputy Attorney General, Karen E. Long, Assistant Attorney General, and William B. Crumpler and Margaret A. Force, Associate Attorneys General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

For Carolina Industrial Group for Fair Utility Rates (CIGFUR):

Ralph McDonald and Carson Carmichael, III, Bailey and Dixon, Attorneys at Law, Post Office Box 12865, Raleigh, North Carolina 27605-2865

For Carolina Utility Customers Association, Inc. (CUCA):

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon and Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28680-1269

BY THE COMMISSION: On July 31, 1992, North Carolina Power (NC Power or the Company) filed an application with the North Carolina Utilities Commission seeking authority to adjust and increase its rates and charges for electric service to its North Carolina retail customers effective on August 30, 1992. NC Power is an unincorporated division of Virginia Electric and Power Company (Vepco). On August 27, 1992, the Commission issued an Order declaring the matter to be a general rate case, suspending the proposed rates, requiring public notice, and scheduling public hearings.

As provided by Commission Rule R8-55, NC Power's fuel adjustment application was due to be filed on September 11, 1992, and a hearing held on November 10, 1992. Docket No. E-22, Sub 335 had been reserved for the 1992 annual fuel charge adjustment proceeding.

On September 4, 1992, NC Power filed a Motion for Consolidation of Hearings in the above-captioned dockets. By its motion, the Company asserted that it intended to file supplemental data updating its testimony in the general rate case with respect to fuel costs and the fuel component of purchased power consistent with the last test period required for its annual fuel charge adjustment proceeding, which was the 12-month period ending June 30, 1992. NC Power therefore proposed that the hearing in its annual fuel charge adjustment proceeding be rescheduled and consolidated with the general rate case hearing scheduled to begin in Raleigh on January 12, 1993.

On September 11, 1992, the Company filed its annual fuel charge adjustment application. On October 5, 1992, the Commission issued an Order consolidating the rate case and fuel clause hearings. In that Order, the Commission provided that the Experience Modification Factor (EMF) shall terminate on December 31, 1992, deferred the implementation of a new EMF until the implementation of base rates in Docket No. E-22, Sub 333, and deferred the implementation of a new fuel cost rider to accommodate the implementation of a new primary fuel component in Docket No. E-22, Sub 333. The Commission also permitted the Company's September 11, 1992 fuel filing to serve as its fuel-related data in its general rate case pursuant to G.S. 62-133(c) and Commission Rule R1-17. Finally, the Commission provided for a consolidated public notice of the rate and fuel proceedings.

The Attorney General filed Notices of Intervention on August 25, 1992, in Docket No. E-22, Sub 333 and on January 7, 1993, in Docket No. E-22, Sub 335, pursuant to G.S. 62-20, on behalf of the using and consuming public.

On August 31, 1992, the Carolina Industrial Group for Fair Utility Rates (CIGFUR) filed a Petition to Intervene in Docket No. E-22, Sub 333, which was allowed by Commission Order dated September 2, 1992. CIGFUR also filed a Petition to Intervene in Docket No. E-22, Sub 335, on October 7, 1992, which was allowed by Commission Order dated October 9, 1992.

On October 5, 1992, the Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene in Docket No. E-22, Sub 333, which was allowed by the Commission on October 6, 1992. CUCA also filed a Petition to Intervene in Docket No. E-22, Sub 335, on October 9, 1992, which was allowed by Commission Order dated October 13, 1992.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Ahoskie:	Bill Early
Elizabeth City:	Georgetta Jackson William Pruden Deborah Fox Cavenaugh Keith Fearing
Williamston:	Kenneth Perry Sheila Godard
Roanoke Rapids:	Edwin Akers

The Company presented the testimony and exhibits of the following witnesses: James T. Rhodes, President and Chief Executive Officer of Virginia Electric and Power Company; William E. Avera, a principal in Financial Concepts and Applications, Inc.; Glen B. Ross, Manager-Planning for Virginia Electric and Power Company; Maxwell R. Schools, Jr., Manager-Regulatory Accounting for Virginia Electric and Power Company; and Andrew J. Evans, Director-Rate Design for Virginia Electric and Power Company.

The Company also introduced the affidavits and exhibits of James P. Carney, Director - Financial Analysis for Virginia Electric and Power Company, and Charles R. Goode, III, Director-Regulatory Accounting for Virginia Electric and Power Company.

The Public Staff presented the testimony and exhibits of the following witnesses: John Robert Hinton, Financial Analyst, Economic Research Division of the Public Staff; Kerim Lamar Powell, Electric Engineer, Electric Division of the Public Staff; Benjamin R. Turner, Jr., Electric Engineer, Electric Division of the Public Staff; James S. McLawhorn, Electric Engineer, Electric Division of the Public Staff; Thomas S. Lam, Electric Engineer, Electric Division of the Public Staff; Kelly B. Dietz, Staff Accountant, Accounting Division of the Public Staff and Michael C. Maness, Supervisor, Electric Section, Accounting Division of the Public Staff.

CIGFUR presented the testimony and exhibits of the following witnesses: Nicholas Phillips, Jr., principal in the firm of Drazen-Brubaker & Associates, Inc., and John P. Murphy, Director of Energy Supply for Champion International.

The Company presented the rebuttal testimony of the following witnesses: Maxwell R. Schools, Jr.; Gary L. Edwards, Manager-Capacity Acquisition of Virginia Electric and Power Company; James P. Carney; Andrew J. Evans; William E. Avera; and John F. Hughes, Jr., Outer Banks District Manager.

Prior to and during the course of the hearings, the parties made various motions and the Commission entered various Orders, all of which are matters of record. Additionally, pursuant to Orders of the Commission or requests of the parties, also of record, certain parties were directed or permitted to submit late-filed exhibits either during or subsequent to the hearings.

Based on the foregoing, the verified application, the testimony and exhibits received into evidence at the hearing, the proposed orders and briefs submitted by the parties, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. NC Power is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. NC Power is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. NC Power is an unincorporated division of Virginia Electric and Power Company and has its office and principal place of business in Richmond, Virginia. Virginia Electric and Power Company is a wholly-owned subsidiary of Dominion Resources, Inc.

2. NC Power is lawfully before this Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133 and for an adjustment in its nuclear and fossil fuel costs pursuant to G.S. 62-133.2.

3. The test period for purposes of the general rate case proceeding (Docket No. E-22, Sub 333) is the 12-month period ended December 31, 1991, adjusted for certain known changes based upon circumstances and events occurring up to the close of the hearing.

4. NC Power, by its general rate case application (Docket No. E-22, Sub 333), sought an increase in its basic rates and charges to its North Carolina retail customers of $21,420,000 consisting of an increase of $22,311,000 in annual basic non-fuel revenues and a decrease in the fuel component of $891,000.

5. The overall quality of electric service provided by NC Power to its North Carolina retail customers is good. The only area of concern is in the Outer Banks, and the Company is taking appropriate action to improve its service there.

6. The Summer/Winter Peak and Average (SWPA) cost allocation method is the most appropriate method for determining the North Carolina retail jurisdictional cost of service.

7. The Summer/Winter Peak and Average (SWPA) cost allocation method is the most appropriate method for determining North Carolina retail customer class cost responsibility.

8. The appropriate level of materials and supplies for use in this proceeding is $13,090,000.

9. The appropriate level of cash working capital investment for use in this proceeding is $(2,458,000).

10. NC Power's reasonable rate base used and useful in providing service to its North Carolina retail customers is $367,831,000, consisting of electric plant in service (including nuclear fuel) of $598,046,000 and materials and supplies of $13,090,000, reduced by accumulated depreciation of $166,889,000, accumulated amortization of nuclear fuel of $36,842,000, accumulated deferred income taxes of $37,101,000, cash working capital of $2,458,000, and other cost-free capital of $15,000.

11. The appropriate level of test year North Carolina jurisdictional sales is 2,521,134 mWh.

12. The appropriate level of unbilled test year sales is 8,795 mWh.

13. The appropriate level of basic rate schedule revenues based on rates in effect as of February 14, 1991, is $134,938,156.

14. The appropriate level of basic revenue related to unbilled sales is $430,599.

15. The appropriate end-of-period level of revenues for load management credits is $(176,117), before reallocation for demand side management (DSM) considerations.

16. The appropriate end-of-period level of revenues related to facilities charges is $408,313.

17. The appropriate level of end-of-period revenues related to miscellaneous service charges is $856,470.

18. The appropriate level of revenue associated with growth, usage, and weather is calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues and test year kWh sales.

19. The mWh adjustments related to weather normalization, customer growth, and increased usage for the 12-month test period through the update period ending September 30, 1992, are (5,308) mWh, (6,447) mWh, and 144,361 mWh, respectively, for a total of 132,606 mWh. These adjustments are appropriate for use in this proceeding.

20. The basic revenue related to weather normalization, customer growth, and increased usage for the test year through the update period ending September 30, 1992, is $6,746,512.

21. The adjusted level of sales for the test year through the update period ending September 30, 1992, is 2,662,535 mWh.

22. The basic revenue related to growth in load management credits for the test period through the update period ending September 30, 1992, is $(6,126).

23. Total rate schedule revenue (excluding fuel revenue) for the test period through the update period ending September 30, 1992, is $142,115,267.

24. For the test period through the update period ending September 30, 1992, total basic adjusted revenue excluding other miscellaneous revenue is $142,683,807 based on the sum of adjusted rate schedule revenue of $142,115,267; less load management credits of $176,117, growth related to load management of $6,126, and allocated DSM cost of $514,000; plus revenue derived from facilities charges of $408,313, plus miscellaneous service revenue of $856,470.

25. The proper level of gross revenue for the Company for the test year (excluding fuel revenue) under present rates and after accounting and pro forma adjustments is $144,377,000.

26. Vepco reported that in 1986 it decided to deal with non-utility generation (NUG) offers by conducting a solicitation because it was receiving NUG capacity offers in amounts greater than its projected needs for the foreseeable future.

27. The Company instituted its solicitation process by sending out a letter on December 23, 1986, to interested developers. The letter was sent to Ultra Cogen Systems, Inc. (Ultra Cogen), at its request on January 13, 1987.

28. The Company sought 700 MW of capacity through its December 1986 solicitation. In response it received bids for 5,083 MW. The Company selected ten projects for negotiation and ultimately signed contracts in June 1987 for seven projects totaling 1,264 MW. Six of these projects are in operation with a dependable capacity of 1,412 MW. The contract for the remaining project has been terminated.

29. In March 1988, Vepco issued a formal Request for Proposals seeking 1,750 MW of capacity. It received bids for 95 projects totalling 14,653 MW. It ultimately signed contracts for 19 projects totalling 2,086 MW. Eleven projects are still active totalling 1,291 MW, seven of which currently are operational with a dependable capacity of 982.4 MW.

30. The Company undertook a solicitation for peaking power in October 1988 from which no contracts were signed. An all source solicitation for 1,100 MW was undertaken in 1989. The 1989 solicitation resulted in 11,000 MW being offered. Contracts were signed for 442 MW and Vepco announced it would build its own 400 MW coal plant. No projects from this solicitation are currently in operation.

31. The Virginia State Corporation Commission (SCC) and the Public Staff have expressed concerns about the Company's capacity planning process, including whether its decisions to buy or build have been based on questionable cost data, its failure to compare its estimated construction costs with each individual NUG project in its winning package, and its bias toward NUG capacity purchases.

32. The contracts the Company has entered into for NUG projects contain a variety of terms regarding how total costs are divided between capacity and energy costs and how capacity costs are structured. The Public Staff has expressed concerns about ratchet arrangements where higher capacity payments are paid in earlier years and lower payments are paid in the final years of the contracts.

33. The Public Staff has not evaluated the reasonableness and appropriateness of individual NUG contracts resulting from the Company's various solicitations. The NUG expenses being allowed in rates as reasonable are being allowed for purposes of this proceeding only.

34. The Hadson projects were originally proposed by Ultra Cogen during the 1986 solicitation and rejected by Vepco because the price proposed was excessive and Ultra Cogen was unwilling to accept certain terms and conditions.

35. Arbitration proceedings were initiated by Ultra Cogen's filing of eight arbitration petitions with the SCC for nine projects (two of which were in West Virginia) between November 12, 1987, and December 3, 1987, requesting the SCC to order Vepco to enter into power purchase agreements.

36. Ultra Cogen's first petition for arbitration, which was filed on November 12, 1987, involved a proposed cogeneration facility at The Lane Company, Inc. (Lane) in Altavista, Virginia (Case No. PUE870088). The petition indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which is of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result.

37. The Virginia SCC issued a policy statement on competitive bidding on January 29, 1988, finding that PURPA does not require a utility to offer full administratively determined avoided cost to qualifying facilities (QFs) and that avoided costs could be determined through competitive bidding.

38. The SCC's policy statement on competitive bidding also provided that in the evaluation of specific proposals favorable weight should be assigned to the use of Virginia fuels, manpower and other state resources, the benefits to be derived by the industries and communities associated with particular projects, and other identifiable economic and societal benefits to the people of the Commonwealth of Virginia.

39. Vepco requested dismissal of the arbitration petitions on the grounds that the SCC had expressed general approval of bidding in its policy statement of January 29, 1988.

40. On February 26, 1988, one month after the SCC's policy statement on competitive bidding, the SCC issued an Order requiring Vepco to negotiate with Ultra Cogen and naming a Commissioner to serve as arbitrator.

41. Ultra Cogen and Vepco agreed that the number of projects to be considered by the SCC would be reduced to four, within Vepco's territory, with Ultra Cogen being allowed to select the four from five potential projects at a later date.

42. Vepco's position in the arbitration proceedings was that the prices resulting from the 1988 solicitation (or, alternatively, the 1986 solicitation) should be used to set the prices in the Ultra Cogen contracts. The arbitrator disagreed.

43. The Virginia arbitrator required the prices for these projects to be based on Vepco's costs of its Chesterfield 7 as those costs were projected on November 12, 1987, the date the first petition for arbitration was filed.

44. Vepco analyzed the projected capacity and energy costs of a unit similar to Chesterfield 7 over a 25-year period.

45. The payments that correspond to the arbitrator's directive were established in the arbitrator's Interim Order dated May 27, 1988, along with other key terms and conditions to be included in a power purchase agreement between the parties. The capacity payments for the Hadson projects were set at $341/kW for the first 15 years.

46. Ultra Cogen's energy prices were established based on the assumption that coal prices would be increasing in the future. Vepco's fuel reports on file with this Commission show that from 1984 through 1987 the cost of coal decreased and has remained relatively stable ever since.

47. The Award and Final Order issued in the arbitration proceedings on September 30, 1988, recognized that the agreements between the parties reflected negotiations and rulings based on the unique circumstances of those proceedings, including that the projects involved coal-fired facilities in lesser populated areas of the Commonwealth.

48. Vepco did not appeal the SCC arbitration orders to the courts.

49. Ultra Cogen subsequently was purchased by Hadson Power and these projects became known as Hadson Power 11 - Southampton, Hadson Power 12 - Altavista, and Hadson Power 13 - Hopewell (the Hadson projects). Hadson was recently purchased by LG&E Development Corporation. These projects are now owned by a conglomerate of limited and general partners, including subsidiaries of Westmoreland Coal and a Chrysler Capital Corporation subsidiary.

50. The Hadson Power 11 - Southampton project came on line on March 7, 1992; the Hadson Power 12 - Altavista project on February 22, 1992; and the Hadson Power 13 - Hopewell project on July 1, 1992. The fourth project is in default.

51. Vepco is currently obligated to pay $64 million on a system basis for capacity costs under three of the four contracts that Vepco entered into with Ultra Cogen as a result of the arbitration proceedings before the Virginia SCC.

52. Vepco did not file any information with this Commission concerning the arbitration proceeding or the resulting capacity costs associated with the arbitrated projects until this proceeding.

53. Vepco has not filed the contracts for the Hadson projects or otherwise sought Commission approval of the capacity or energy costs of the projects except in its application in this rate case.

54. The average capacity cost of the 1986 projects is $141/kW. If this capacity cost were used to adjust the Hadson projects' capacity costs of $341/kW, $1.63 million of the capacity costs would be unreasonable and subject to disallowance.

55. The average capacity cost of the 1988 projects is $171/kW. If this capacity cost were used to adjust the Hadson projects' capacity costs of $341/kW, $1.39 million of the capacity costs would be unreasonable and subject to disallowance.

56. The same Virginia Commissioner who served as arbitrator in the proceeding involving the Ultra Cogen projects issued an Order in 1990 concerning Doswell Limited Partnership's application for approval of the construction of a 650 MW NUG project. This Order indicated that Doswell's anticipated contractual payments were based upon the avoided costs of Chesterfield 7 and that these contractual payments were considered reasonable. The capacity costs for the Doswell project sought to be recovered in this proceeding are $146/kW.

57. This Commission is not bound by actions of the SCC with regard to the Hadson projects.

58. While the average capacity cost for the 1986 solicitation could be used to adjust the capacity costs for the Hadson projects, the average capacity cost for the operational projects resulting from the 1988 solicitation is more appropriate.

59. It is appropriate to reduce the Company's operation and maintenance expense by $1,390,000 to reflect unreasonable purchased capacity costs.

60. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended in whole or in part to compete with natural gas utilities or with other energy providers. The amount of these advertising costs to be removed in this case totals $54,000.

61. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended to promote the sale of electricity in a manner inconsistent with the provisions setting forth the allowable types of such advertising in Commission Rules R12-12 and R12-13. The amount of these advertising costs to be removed in this case totals $11,000.

62. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended to enhance the Company's image or to achieve other objectives not related to the provision of safe and reliable electric utility service. The amount of these advertising costs to be removed in this case totals $13,000.

63. The Public Staff adjustment to exclude $28,000 from expenses, representing 50% of the North Carolina retail portion of the compensation of the officers most closely linked with meeting the demands of the Company's common stockholder, is reasonable and appropriate for purposes of this proceeding.

64. The Public Staff adjustment to remove $10,000 related to community and government affairs projects and $89,000 of other charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

65. The Public Staff adjustment to increase operation and maintenance expense by $41,000 to reflect common stock issuance costs is reasonable and appropriate for purposes of this proceeding.

66. The level of operation and maintenance expense (other than fuel) under present rates appropriate for use in this proceeding is $75,065,000.

67. It is appropriate, for purposes of this proceeding, to remove the remaining North Anna Unit 3 loss amortization of $1,306,000 from depreciation and amortization expense. It is also reasonable and appropriate to establish a rate rider of 0.066328¢/kWh, to expire one year from the date of this Order, for the purpose of allowing the Company to recover the remaining unamortized loss.

68. The level of depreciation and amortization expense appropriate for use in this proceeding is $20,606,000.

69. The level of other tax expense under present rates appropriate for use in this proceeding is $11,100,000.

70. The Public Staff adjustment of $(4,000) to reflect the use of an average North Carolina state income tax surcharge rate of 1.5% is reasonable and appropriate for purposes of this proceeding.

71. Based on the other findings and conclusions set forth in this Order, the appropriate level of income tax expense under present rates for use in this proceeding is $8,607,000.

72. The level of other interest expense appropriate for use in this proceeding is $208,000.

73. The level of interest on tax deficiencies appropriate for use in this proceeding is $171,000.

74. The reasonable level of test year operating revenue deductions for NC Power (excluding fuel expense) after normalization and pro forma adjustments, under present rates, is $115,757,000.

75. The proper capitalization ratios for use in this proceeding are as follows:

Long-Term Debt	45.227%
Preferred Stock	9.955%
Common Equity	44.818%
Total	100.000%

76. The proper embedded cost rates of long-term debt and preferred stock for use in this proceeding are 8.024% and 5.598%, respectively.

77. Estimates of the cost of common equity capital derived by use of both the constant growth form of the discounted cash flow (DCF) model and the FERC risk premium model should be accorded the greatest weight in determining the appropriate cost of equity in this proceeding.

78. The non-constant growth DCF model and the risk premium methods employed by witness Avera should be accorded only minimal weight in this proceeding.

79. The Company does not plan a public offering of its common stock in the near future.

80. In a foregoing finding of fact, an adjustment has been made to the cost of service for actual jurisdictional test-year expenses associated with the Company's stock purchase plans. No further adjustment to cost of service, rate base, or cost of capital to compensate for flotation costs is appropriate.

81. The appropriate cost of common equity for use in this proceeding is 11.80%.

82. Combining the capitalization ratios and the cost rates for each component of capital adopted for use herein, the Commission finds that the rate of return which the Company should be allowed an opportunity to earn on its rate base is 9.48%.

83. NC Power should be authorized to increase its annual level of gross revenues under present rates by $10,642,000 (excluding fuel revenue). After giving effect to the approved increase, the annual revenue requirement for NC Power (excluding fuel revenue) is $155,019,000, which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

84. The revenue increase adopted herein should be distributed to the various customer classes as follows:

	Rate of Increase Index
Residential	1.125
Small General Service	1.0
Large General Service	0.875
Outdoor Lighting	1.0
Traffic Signals	1.0
Overall	1.0

85. The summer/winter differential of 1.0¢/kWh is appropriate for setting residential non-time of use rates in this case.

86. The basic customer charge for residential non-time of use rates should be set to a level of $9.50 per month in designing rates to produce the level of revenue found appropriate for the residential rate class in this case.

87. NC Power proposed a new Line Extension Plan as a part of its original filing in this proceeding. The plan was subsequently modified during the hearing by means of a stipulation between the Company and the Public Staff regarding revised language that would permit a residential customer to request overhead construction rather than underground construction in the application of the revenue test.

88. The proposed new Line Extension Plan will recover approximately $1 million per year more from new residential customers and approximately $75,000 per year more from new non-residential customers.

89. More complete recovery of investment in new distribution plant will help delay future general rate increases, and it will avoid much of the investment for new customers that has been charged to existing customers.

90. Overhead line extensions should continue to be available to customers requesting overhead service, and associated construction costs should be determined on a case-specific basis.

91. The proposed new Line Extension Plan, as modified during the hearing, is appropriate and should be approved to become effective 90 days after the date of this Order.

92. The Company offers a reduction to residential energy and demand charges for customers whose dwellings meet certain thermal integrity requirements.

93. Historically, the thermal requirements to qualify for the reduction have been substantially more stringent than those required by the North Carolina Building Code for all residential construction.

94. The North Carolina Building Code Council has adopted new residential building standards to be effective April 15, 1993, which are substantially more stringent than those currently in place.

95. NC Power has agreed to file new revised standards to qualify for the residential conservation reduction (RCR) prior to April 15, 1993.

96. It is appropriate to modify Schedule 6C, Schedule 5G, and Schedule CS to allow for two curtailment requests per day during the winter season as proposed by the Company.

97. The rate designs and rate schedules proposed by the Company are reasonable and appropriate except as specifically modified herein.

98. The change proposed by the Company to paragraph II.A.1 of the Company's Terms and Conditions for the delivery of electric service rules and regulations has been withdrawn at this time and should not be approved.

99. The Terms and Conditions proposed by the Company are reasonable and appropriate except as specifically modified herein.

100. The test period for the fuel clause proceeding (Docket No. E-22, Sub 335) is the 12-months ending June 30, 1992.

101. The fuel proceeding test period per book system sales are 57,794,906 mWh.

102. The fuel proceeding test period per book system generation is 61,448,089 mWh which includes various energy generations as follows:

	mWh
Coal	25,992,366
Internal Combustion	1,413,808
Heavy Oil	1,912,993
Natural Gas	87,836
Nuclear	22,978,300
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,268,968
Other	5,234,861
Interruptible Sales	(2,551,212)

103. The normalized system nuclear capacity factor which is appropriate for use in this proceeding is 69.24%.

104. The normalized generation is based on the 12-month test period ending June 30, 1992.

105. The adjusted test period sales of 58,613,478 mWh results from an additional 280,695 mWh of customer growth, 183,068 mWh of additional customer usage, and an additional 354,789 mWh associated with weather normalization added to fuel test period system sales of 57,794,906 mWh.

106. The adjusted test period system generation for use in this proceeding is 62,309,169 mWh which includes various energy generations as follows:

	mWh
Coal	28,130,404
Internal Combustion	1,530,090
Heavy Oil	2,070,346
Natural Gas	95,061
Nuclear	20,474,196
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,784,633
Other	5,665,469
Interruptible Sales	(2,551,212)

107. The appropriate fuel prices for use in this proceeding are as follows:

A. The coal fuel price is $14.26/mWh.

B. The nuclear fuel price is $4.59/mWh.

C. The heavy oil fuel price is $24.90/mWh.

D. The natural gas price is $30.59/mWh.

E. The internal combustion turbine (IC) fuel price is $21.33/mWh.

F. The fuel price for other purchased and interchanged power is $15.12/mWh.

G. The total fuel cost for interruptible sales is $28,446,000.

H. Hydro, pumped storage, and non-utility generation (NUG) have a zero fuel price.

108. The adjusted system fuel expense for the July 1, 1991, to June 30, 1992, test period for use in this proceeding is $639,430,000.

109. The appropriate base fuel factor for this proceeding is 1.091¢/kWh, excluding gross receipts tax.

110. The Company's North Carolina test period jurisdictional fuel expense overcollection is $1,308,510. The adjusted North Carolina jurisdictional test year sales are 2,629,412 mWh.

111. Interest expense associated with the overcollection of test period fuel revenues amounts to $218,085, based upon a 10% annual interest rate.

112. The Company's Experience Modification Factor (EMF) and interest combine for a decrement of 0.058¢/kWh, excluding gross receipts tax.

113. The final fuel factor is 1.033¢/kWh, excluding gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact is contained in the Company's application and in the Commission's records. These findings are generally informational and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony of Company witnesses Rhodes and Hughes and the public witnesses who appeared in Ahoskie, Elizabeth City, Williamston, and Roanoke Rapids. The only witness to complain about service was public witness William Pruden, who addressed service reliability on the Outer Banks. Witness Pruden was particularly concerned about multiple interruptions, or "blips", in the service. Witness Hughes acknowledged that the Outer Banks present a special problem for the Company and described the steps NC Power is taking to overcome these problems, including spraying of the lines to remove storm driven salt spray. Based on the single complaint of witness Pruden as compared to the multiple witnesses praising the Company, and on the steps the Company is taking to address the Outer Banks situation, the Commission concludes that NC Power is providing good service to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence as to the reasonableness of the allocation of the Vepco system cost to the North Carolina retail jurisdiction is found in the testimony and exhibits of Company witness Evans, Public Staff witness Turner and CIGFUR witness Phillips.

Both Company witness Evans and Public Staff witness Turner recommended the use of the Summer/Winter Peak and Average (SWPA) method for determining jurisdictional allocation and the revenue requirement for the North Carolina retail jurisdiction. CIGFUR witness Phillips did not agree.

As discussed elsewhere herein, the Commission concludes that the SWPA method is the most appropriate cost allocation method for determining jurisdictional allocation and the revenue requirement for the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence as to the most reasonable method for determining North Carolina retail customer class cost responsibility is found in the testimony of Company witness Evans, Public Staff witness Turner, and CIGFUR witness Phillips.

While the Company's witness recommended the use of the Summer/Winter Peak and Average (SWPA) method for determining jurisdictional cost responsibility and revenue requirement, he recommended that the Average and Excess method (A&E) be used to determine customer class cost responsibility. The Public Staff witness recommended that the SWPA method be used to determine both jurisdictional cost responsibility and customer class cost responsibility. The witness for CIGFUR agreed with the Company that the SWPA method was not appropriate for determining customer class cost responsibility.

Witness Evans explained that the factors to be considered in allocating the generating or production cost of the system among its customers should be consistent with the production cost each customer class load imposed on the utility. This system cost is a function of peak loads, which require a utility to build or purchase capacity, and of energy consumption, which dictates the type of plant to be built or the type of power to be purchased. Base load plants require high capital costs but have lower fuel costs and are expected to operate many hours a year. Peaking plants have low capital costs but have high fuel costs and operate for only a few hours a year. Intermediate plants have moderate capital costs and fuel costs and operate many more hours than peaking units but fewer hours than base load units. The type of plant the Company builds is based on total costs, including both fixed and variable costs. The decision to build base load capacity is expected to reduce operating costs through the use of lower heat rates and lower cost fuel; therefore, the cost of base load capacity should be viewed as having been incurred, at least in part, to provide lower cost energy. Witness Evans stated that he believed the demand allocation factor should be energy weighted in some fashion in order to recognize that the annual kWhs consumed have capacity costs associated with them.

Witness Evans testified that all customers benefit from the diversity in usage patterns that arises from serving a variety of customer classes because such diversity results in a reduction in total capacity requirements for the system. He pointed out that the total system peak load is always less than the sum of the individual customer class peak loads, reflecting the diversity of usage patterns. He proposed that such customer class diversity should be recognized in the cost allocation process by utilizing the maximum peak load for each class as an allocation factor rather than the load for each class at the time of the system peak. The use of the class peak loads rather than the coincident peak loads for each class is what distinguishes the A&E method from the SWPA method.

Witness Evans testified that a weakness of the SWPA method was its use of both summer and winter peaks, and he insisted that the Company's summer peak alone is the driving criteria behind the Company's capacity expansion plan. He contended that the SWPA method would allow a customer class to increase its contribution to one seasonal system peak while decreasing its contribution to the other seasonal system peak as a means of reducing its overall demand related allocation factor.

Public Staff witness Turner recommended that the Commission continue to approve the SWPA cost allocation method for use in determining both jurisdictional and customer class cost responsibility in this case. He stated that this method has been approved by the Commission in the Company's previous two proceedings since 1983: Docket Nos. E-22, Sub 273 and 314. The method has also been approved for use in all CP&L general rate cases since 1982: Docket Nos. E-2, Sub 444, Sub 461, Sub 526, and Sub 537.

Witness Turner explained that the SWPA method uses an allocation factor based on two components weighted by system load factor. The first component is based on the average of summer and winter peaks at the time of the system's peak demand. The second component is based on average demand for the year. System load factor is used as a proxy for determining the portion of plant allocated by average demand. Although the amount of production capital required to produce energy is not precisely known, use of load factor as a proxy works well in this regard because it will allocate more plant by average demand as the load factor increases and less plant as the load factor decreases. Similarly, as the Company's system load factor increases system planning will tend to meet additional load requirements with base load capacity. Conversely, as system load factor declines system planning will tend toward peaking units to meet additional load requirements.

Witness Turner stated that an analysis of investment in generating plant required to meet the system minimum load shows that approximately 60% of the Company's total production plant investment is required to meet the system's minimum load. The minimum load of 4,132 MW maintained continuously equates to an energy requirement of 36,196,320 mWh. To meet this demand or to produce this minimum energy requirement, the Company dispatches its most efficient units, which also are the units with the greatest investment per MW. The investment in these units represents approximately 60% of the Company's total investment in production plant.

Witness Turner explained that the SWPA allocation method recognizes that generating units are built to run for varying periods of time and that the increased cost to build base load units is related to average demand or energy. Peaking units, costing in the order of $400 to $500 per kW, are built to run only during the times of peak demands. These units have the lowest capital cost and highest fuel cost and are not considered economical to run except for a few hours a year. Base load units, costing in the range of $1,000 to $2,000 per kW, require the largest capital investment but have the advantage of low fuel cost (0.5 to 1.5¢/per kWh.) They are proven economical because of the required long running time. The difference in capital cost is, therefore, related to the long run time or total energy produced. Because a portion of the base load unit fixed cost investment is related to providing long running capability at low fuel cost, it is reasonable to allocate a portion of the fixed cost investment by using average demand.

CIGFUR witness Phillips testified that the SWPA method is no longer appropriate for cost allocation between customer classes. He contended that the SWPA method does not accurately reflect the cost causation of each class and is in direct conflict with demand side management programs. He stated his preference for the summer coincident peak allocation method, but indicated that if the Commission determines that energy usage should be a part of the cost allocation formula, the A&E method is more appropriate than the SWPA method.

CUCA supported the position of NC Power and CIGFUR on cost allocation, and the Attorney General supported the position of the Public Staff. CUCA insisted that all fixed costs of production plant should be classified as demand related and that any allocation of fixed costs by energy usage unlawfully discriminates against industrial customers. The Attorney General contended that CIGFUR's and CUCA's support for the A&E method reflects the fact that it produces results similar to the coincident peak method they usually support even though the A&E method includes an allocation of some fixed costs based on energy usage.

The Commission is of the opinion that the SWPA method should be retained in this proceeding for cost allocations between jurisdictions and between customer classes. The Commission is not persuaded that the diversity in class usage patterns provides sufficient justification for utilizing class maximum peaks in the allocation formula rather than class coincident peaks. The class coincident peaks are also a measure of diversity between classes, and they are related to the needs of the entire system as a whole. This becomes significant in view of the fact that generating units are designed to meet the needs of the entire system as a whole, not the needs of any individual class of customer. Since the only real difference between the A&E method and the SWPA method is the use of class maximum peaks by the A&E method and the use of class coincident peaks by the SWPA method, the SWPA method better reflects the diversity between class usage patterns as related to the system as a whole.

The Commission is also not persuaded in this proceeding that the allocation formula should exclude consideration of energy usage as suggested by CIGFUR and CUCA. The reasons remain the same as explained in previous general rate orders for both NC Power and for Carolina Power & Light Company. In brief, large base load generating units, which constitute the lion's share of the fixed cost investment in generating plant, are designed to achieve lower operating costs over their entire period of operation. While operation of such base load units is essential during peak periods, the large fixed cost investment in such units can only be justified by the savings in operating costs for such units during nonpeak periods.

The Commission is also not persuaded that use of both the summer coincident peak and the winter coincident peak for the demand related allocation factor is a weakness in the SWPA method. Use of only a summer coincident peak or only a winter coincident peak could give some customer classes a free ride, due to the fact that some classes may contribute greatly to one of the peaks and hardly anything to the other.

Company witness Evans testified that determination of an allocation method for fixed costs of production should also consider how fuel costs are recovered. He indicated that an allocation method should match the recovery of fixed costs with the average recovery of fuel costs. He recommended in his rebuttal testimony that if the Commission adopted the SWPA method for cost allocation between customer classes in this proceeding, an additional $1.3 million should be allocated to all classes except the Large General Service (LGS) class in order to compensate the LGS class for the fact that most of the LGS class kWh usage comes from low fuel cost generation. However, he agreed on cross-examination that if a greater share of low cost nuclear fuel is allocated to the LGS class, then a greater share of nuclear decommissioning cost should be allocated to them as well.

CIGFUR witness Phillips testified that if the adopted cost allocation method is premised on the theory that some customer classes utilize more of the base load generating plants than others, then the lower energy costs resulting from those base load plants should also be allocated to those classes. He stated that there should be symmetry between allocation of fixed costs and energy related costs in any method. He contended that if the Commission allocates a greater share of the fixed costs of base load units to the LGS class, then the LGS class should be allocated a greater share of the low fuel costs from those base load units.

In response to the Company's and CIGFUR's concern about fuel allocation under the SWPA method, witness Turner stated that the Public Staff would be receptive to proposals to charge different energy costs to different customer classes. He explained that the information needed to do such an allocation would have to be provided by the Company and would have to include such data as the load shape for the various customer classes and the amount of fuel cost associated with each plant supplying power to those customer classes. In response to questions on re-direct, witness Turner stated that information needed to make recommendations on cost of service comes from the Company. In this case the Company filed Commission-ordered cost studies, but it did not file a fuel allocation study, and it has not been ordered to do so by the Commission.

The Commission concludes that the Company should make a study of the fuel costs and other energy costs incurred to serve the LGS customer class relative to the remainder of the system. The study should also attempt to determine the fixed costs of generating units required to serve the LGS customer class relative to the remainder of the system to the extent it is feasible to do so. The studies may be based upon the fixed costs and variable costs of the generating units actually dispatched to serve the LGS class load, or they may be based upon a production simulation model or other method agreed upon between the Company and the Public Staff. The Commission is further of the opinion that the Company and the Public Staff should attempt to agree on mutually acceptable criteria for making the studies, and that they should seek appropriate input and comment on making the study from CIGFUR, CUCA and any other party to this proceeding who desires to participate. The results of the studies and supporting workpapers should be filed with the Commission and the Public Staff within 12 months after the date of this Order. The Company should also file quarterly reports with the Commission regarding the progress of the studies and agreements as to study criteria and methodology, with the first report due approximately three months after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The amount of materials and supplies proposed by both the Public Staff and the Company is $13,090,000.

Based on the foregoing, the Commission concludes that the appropriate level of materials and supplies for use in this proceeding is $13,090,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The amount of cash working capital investment proposed by both the Public Staff and the Company is $(2,458,000).

Based on the foregoing, the Commission concludes that the appropriate level of cash working capital investment for use in this proceeding is $(2,458,000).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The rate base proposed by both the Public Staff and the Company is $367,831,000.

Based on the foregoing, the Commission concludes that the Company's reasonable rate base used and useful in providing service to its North Carolina retail customers for purposes of this proceeding is $367,831,000, made up of the following components:

Item	Amount (000's)
Electric plant in service including nuclear fuel	$598,046
Accumulated depreciation	(166,889)
Accumulated amortization of nuclear fuel	(36,842)
Net electric plant in service	394,315
Materials and supplies	13,090
Cash working capital	(2,458)
Accumulated deferred income taxes	(37,101)
Other cost-free capital	(15)
Total rate base	$367,831

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-17

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and was not opposed by any party.

The testimony and exhibits of witness Evans show the level of sales and revenues for the test period ending December 31, 1991, through the update period ending September 30, 1992, as follows:

Sales	mWh
North Carolina jurisdictional sales	2,521,134
Unbill~~ed sales~~	8,795

Basic Revenues	Amount
Basic rate schedules	$134,938,156
Unbilled revenues	430,599
Load management credits	(176,117)
Facilities charges	408,313
Miscellaneous service charges	856,470
Total	$136,457,421

There is no other evidence in the record contesting the level of sales and revenues discussed above. The Commission concludes that these levels are reasonable for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-21

The evidence for these findings of fact is based on the testimony and exhibits of Company witness Evans and Public Staff witness Turner.

Witness Evans filed testimony and exhibits adjusting per book sales and revenues related to weather normalization, customer growth, and increased usage for the test period ending December 31, 1991, through the update period ending September 30, 1992. Witness Evans' adjustment is $6,746,512 based on an adjustment of 132,606 mWh of additional sales. The Public Staff accepted these numbers.

The Commission concludes that the adjustment for weather normalization, customer growth, and increased usage is reasonable and appropriate for use in determining the end-of-period level of kWh sales and revenues. The appropriate adjustment to revenues for the period ending December 31, 1991, through the update period ending September 30, 1992, due to weather normalization, customer growth, and increased usage is $6,746,512 based on additional sales of 132,606 mWh.

Based on the foregoing conclusions, for the test period ending December 31, 1991, through the update period ending September 30, 1992, the reasonable and appropriate adjusted level of sales is as follows:

	mWh
North Carolina Jurisdictional Sales	2,521,134
Unbilled sales	8,795
Weather normalization	(5,308)
Customer growth	(6,447)
Increased usage	144,361
Total	2,662,535

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-24

With the exception of the allocation of DSM cost, the evidence in the record supporting these findings of facts is contained in the testimony and exhibits of Company witness Evans and was not contested by any party. The evidence in the record as to the appropriate assignment of DSM cost is found in the testimony of witness Evans and CIGFUR witness Phillips.

Company witness Evans filed supplemental testimony proposing an adjustment to North Carolina jurisdictional expenses based on the DSM Cost Recovery Joint Stipulation between NC Power and the Public Staff in Docket No. E-100, Sub 64. The adjustment allocates certain DSM revenue credits to the North Carolina jurisdiction whereas the Company's original filing directly assigns the credits. The adjustment of $(514,000) is the difference in the expenses allocated and directly assigned.

CIGFUR witness Phillips testified that because cost could be directly assigned, it is unnecessary to allocate DSM costs. Witness Phillips argued that allocation of cost should be used when booked data necessary to determine cost responsibility does not exist.

Based on the evidence in the record, the Commission concludes that allocation of DSM credits as proposed by the Company is reasonable and appropriate. The Commission concludes that allocation of system-wide DSM costs is appropriate because all customer classes and jurisdictions benefit from DSM programs. While all classes may not participate in a particular DSM program, all classes do benefit from the overall benefits of DSM. It is therefore equitable for all classes to bear a portion of the cost of DSM programs. Thus, the DSM related adjustment of $(514,000) is reasonable.

Based on the foregoing conclusions and the Commission's previous conclusions, the Commission now concludes that the reasonable and appropriate level of end-of-period revenues, excluding other miscellaneous revenue, for the test period ending December 31, 1991, through the update period ending September 30, 1992, is $142,683,807 as shown below:

	Amount
Basic rate schedule revenues	$134,938,156
Unbilled revenues	430,599
Weather normalization, customer growth and increased usage revenues (including growth in load management)	6,746,512
Subtotal	142,115,267
Load management credit	(176,117)
Load management growth	(6,126)
DSM cost allocation adjustment	(514,000)
Facilities charges	408,313
Miscellaneous service charges	856,470
Total	$142,683,807

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the exhibits and other data and records filed by the Company in this proceeding. In addition to the end-of-period revenue of $142,683,807, found reasonable and appropriate in the Evidence and Conclusions for Findings of Fact Nos. 22-24, the Company recorded during the test year $1,824,000 in other miscellaneous revenue. Additionally, the Company made an adjustment of $(159,000) to annualize pole attachment revenue and adjustments totalling $28,000 to annualize Old Dominion Electric Cooperative reserve revenue. No party contested the inclusion of either the per books other miscellaneous revenue or the adjustments made by the Company.

The Commission therefore concludes that the proper gross revenue for the test year (excluding fuel revenue) under present rates and after accounting and pro-forma adjustments is $144,377,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-33

The evidence for these findings of fact is found in the testimony of NC Power witnesses Rhodes and Ross and Public Staff witness Powell. The prefiled revised testimony of Company witness Ross indicated that during the period December 28, 1990, through November 30, 1992, 16 additional NUGs declared commercial operation with a combined summer capability of 1,760 MW. These NUG projects and their commercial operation dates were listed on his Exhibit GBR-1, Schedule 6, revised. These are as follows:

NUG Additions	Date On-line
Battersea Dam	12/31/90
Richmond Power Enterprises	03/13/91
Dale	03/29/91
Wythe Park Power #3	07/29/91
I-95 Landfill	01/01/92
Hadson #12 - Altavista	02/22/92
Hadson #11 - Southampton	03/07/92
Cogentrix of Richmond #1	05/01/92
Doswell #2	05/03/92
North Branch Project	05/05/92
Doswell #1	05/10/92
Commonwealth Atlantic LP	06/05/92
Harvell	06/30/92
Hadson #13 - Hopewell	07/01/92
Cogentrix of Richmond #2	08/01/92
Mecklenburg	11/06/92

NC Power witness Rhodes testified that in 1986 Vepco decided to deal with NUG offers by conducting a solicitation because it believed it was receiving NUG capacity offers in amounts greater than its projected needs for the foreseeable future. The Company instituted its solicitation process by sending out a letter on December 23, 1986, to all developers with whom the Company had contact or who had shown an interest in executing a purchased power agreement with the Company.

Witness Rhodes further testified, in response to questions from the Public Staff on cross-examination, that the Company sought 700 MW of capacity through its December 1986 solicitation and received bids of 5,083 MW in response. The Company selected ten projects for negotiation and ultimately signed contracts in June 1987 for seven projects totaling 1,264 MW. Six of these projects are in operation with a summer capacity rating of 1,305 MW and an average capacity rating of 1,412 MW. Vepco's status report filed on August 30, 1992, in Docket No. E-100, Sub 41, indicates that the one remaining project from the 1986 solicitation was placed in default on July 23, 1991.

In March 1988, Vepco issued a formal Request for Proposals seeking 1,750 MW of capacity. It received bids for 95 projects totalling 14,653 MW. It ultimately signed contracts for 19 projects totalling 2,086 MW. Eleven projects are still active totalling 1,291 MW, seven of which currently are operational with a dependable capacity of 982.4 MW.

Witness Rhodes further testified that the Company undertook a solicitation for peaking power in October 1988, from which no contracts were signed. An all-source solicitation for 1,100 MW was undertaken in 1989, which resulted in 11,000 MW being offered. Contracts were signed for 442 MW and Vepco announced it would build its own 400 MW coal plant. No projects from this solicitation are currently in operation.

In response to cross-examination questions from the Public Staff, NC Power witness Rhodes conceded that the Virginia SCC had expressed significant concerns about the Company's capacity planning process, including whether its decisions to buy or build have been based on questionable cost data, its failure to compare its estimated construction costs with each individual NUG project in its winning package, and its bias toward NUG capacity purchases.

In response to cross-examination by the Public Staff, witness Rhodes also stated that the Company did not use a Company-built option for a direct comparison on a unit-by-unit basis in the spring of 1988 solicitation. He explained that what the Company did was make sure that the package of NUG projects for which Vepco signed contracts was cheaper than the amount it would have cost the Company to have built that capacity itself. He agreed on cross-examination that there was a significant risk that the low-priced winning bidders could fall out leaving the Company only with the relatively high-priced ones.

With regard to the concerns of the Public Staff, witness Powell testified that the contracts the Company has entered into for NUG projects contain a variety of terms regarding how total costs are divided between capacity and energy costs and how capacity costs are structured. Of particular concern to witness Powell were the ratchet arrangements where higher capacity payments are paid in earlier years and lower payments are paid in the final years of the contracts.

Witness Powell also testified that the Public Staff had not evaluated the reasonableness and appropriateness of individual NUG contracts resulting from the Company's various solicitations. He indicated that the Public Staff had focused on the reasonableness of the NUG expenses at issue in this proceeding.

On May 7, 1987, the Commission entered an Order in Docket No. E-100, Sub 53, establishing standard rates and contract terms for qualifying facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and G.S. 62-156(b). In that Order, the Commission stated that:

> Negotiated contracts between a utility and a qualifying facility should, upon execution, be submitted to the Commission. The Commission will conduct a general review of such contracts to determine whether they comply with the provisions of this Order. If it appears that they do, such contracts will be approved for filing with the Commission. The Commission may, on its own motion, conduct further, more detailed review of the contracts at that time by way of such hearings or other proceedings as it may order. Further, such contracts, after being approved for filing, shall be subject to review in the context of the utility's next filed general rate case or by a complaint proceeding, just as would any other contract by the utility. By this procedure, the Commission seeks to ensure that a meaningful and public review is conducted with respect to such contracts.

The Public Staff, through witness Powell, states that it has not evaluated the appropriateness of any of the individual NUG contracts at issue in this proceeding; i.e., those projects currently in commercial operation. The Public Staff has raised a number of concerns regarding the reasonableness of the various NUG contract terms related to capacity payments. According to our Order in Docket No. E-100, Sub 53, the contracts in question should have been investigated in this rate case. The Public Staff was, however, apparently unable to evaluate NC Power's NUG contracts during the course of its investigation. That being the case, the Commission hereby requests the Public Staff to investigate the contracts in question and any other NUG contracts for projects which begin commercial operation after the date of this Order and present the results of such investigation during NC Power's next general rate case in order to ensure that a meaningful and public review has been conducted. Until such time as the NUG contracts in question have been investigated by the Public Staff, the Commission finds good cause to include in rates, as recommended by the Public Staff, a reasonable and representative level of NUG capacity costs for purposes of this proceeding only.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-59

The evidence for these findings of fact is found in the testimony of Company witnesses Ross and Edwards, the testimony of Public Staff witness Powell, and exhibits associated with their testimony.

Company witness Ross testified that during the period December 28, 1990, through November 30, 1992, 16 additional NUGs declared commercial operation. Public Staff witness Powell testified that he examined the reasonableness of the NUG capacity payments that NC Power has requested in this proceeding. He recommended an adjustment with respect to three NUG projects, which will be referred to hereinafter as the Ultra Cogen projects or the Hadson projects.[2] Vepco entered into the three contracts at issue with Ultra Cogen Systems, Inc., (Ultra Cogen) as a result of arbitration proceedings before the Virginia State Corporation Commission (SCC). Vepco currently is obligated to pay $64 million on a system basis for annual capacity costs for the three Hadson projects and is seeking to recover the North Carolina retail jurisdictional allocation of these costs, approximately $2.8 million. The Public Staff recommends that $1.39 million of these capacity costs be disallowed for ratemaking purposes in North Carolina. A history of these projects is necessary to understand the issues presented.

Vepco's December 1986 solicitation letter was sent to Ultra Cogen, at its request, on January 13, 1987. Ultra Cogen proposed nine projects. Ultra Cogen's proposals were rejected in March 1987 because the proposed price was excessive and Ultra Cogen was unwilling to accept certain terms and conditions. Vepco offered to purchase energy only from Ultra Cogen, and it suggested that Ultra Cogen participate in the Company's next solicitation if Ultra Cogen wished to sell capacity. Vepco selected other proposals from the 1986 solicitation. Six of these projects have come on line, and they average $141/kW for capacity payments.

In October 1987 the Virginia SCC initiated a generic review of certain policy issues with respect to competitive bidding schemes such as Vepco's

[2]The projects were developed by Ultra Cogen Systems, Inc. Ultra Cogen subsequently was purchased by Hadson Power, and these projects became known as Hadson Power 11 - Southampton, Hadson Power 12 - Altavista, and Hadson Power 13 - Hopewell. Hadson was recently purchased by LG&E Development Corporation. These projects are now owned by a conglomerate of limited and general partners, including subsidiaries of Westmoreland Coal and a Chrysler Capital Corporation subsidiary.

solicitation. The SCC issued a policy statement on competitive bidding in Case No. PUE870080 on January 29, 1988. In this order, the SCC concluded that federal law does not require a utility to pay full administratively determined avoided costs and that avoided costs may be determined through competitive bidding. It stated that "we believe a system of competitive negotiation such as we have described would be a very efficient and fair means of approximating real, not theoretical, avoided costs." The SCC's policy statement went on to provide that in evaluating specific proposals, favorable weight should be assigned to the use of Virginia fuels, manpower, and other State resources; the benefits to be derived by the industries and communities associated with particular projects; and other identifiable economic and societal benefits to the people of Virginia.[3] With this policy statement in hand, Vepco put together its 1988 solicitation.

While the SCC's generic review was underway, Ultra Cogen initiated arbitration proceedings for its nine projects (two of which were in West Virginia) by filing arbitration petitions with the SCC between November 12, 1987, and December 3, 1987. Ultra Cogen asked the SCC to order Vepco to enter into power purchase agreements including payments for capacity. Ultra Cogen's first petition for arbitration involved a proposed cogeneration facility at The Lane Company, Inc. (Lane) in Altavista, Virginia (Case No. PUE870088). The petition indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result.

Vepco requested dismissal of the petitions on the ground that the SCC had expressed its general approval of competitive bidding in its January 29, 1988, Order in Case No. PUE870080. The SCC refused to dismiss and decided that it would arbitrate Ultra Cogen's petitions by Order dated February 26, 1988, one month after the SCC's policy statement on competitive bidding. The SCC stated that it would approach the arbitrations in an innovative fashion, designed to deal with the subject in a prompt but effective manner. The SCC designated Commissioner Harwood to serve as arbitrator and provided that the arbitrator's conclusions would be final and that Vepco would be bound by them. The SCC ruled that the arbitration would develop appropriate contracts <u>for capacity purchases</u> by Vepco from Ultra Cogen and that the amount of the capacity to be sought by future solicitations would be limited by the amount of capacity resulting from the arbitration.

Vepco issued its 1988 solicitation letter on March 1, 1988. Vepco's position in the arbitration proceedings was that the prices resulting from the 1988 solicitation (or, alternatively, the 1986 solicitation) should be used to set prices for the Ultra Cogen contracts. (This is the position now taken by the Public Staff and opposed by the Company.) The Virginia arbitrator disagreed. By a memo issued on April 27, 1988, he required the contracts to be based on avoided costs of Vepco's Chesterfield 7 as those costs were projected on

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[3]It is worth noting that this Commission lists various factors which we expect utilities to consider in negotiating with QFs, but we do not list factors such as these.

November 12, 1987, the date the first petition for arbitration was filed. This memo was issued by the arbitrator two months into Vepco's 1988 solicitation.

The arbitrator followed up just one month later with an Interim Order of May 27, 1988, in which he established capacity and energy prices, along with other key terms and conditions, for the Ultra Cogen projects. He established the capacity price at $341/kW for the first 15 years of operation. Ultra Cogen's energy prices were established based on the assumption that coal prices would increase in the future. In fact, Vepco's fuel reports on file with this Commission show that from 1984 through 1987 the cost of coal was decreasing and that it has remained relatively stable ever since. The arbitrator noted that Ultra Cogen and Vepco had agreed that the number of projects would be reduced to four projects within Vepco's service territory.

Draft contracts were subsequently submitted, and the arbitrator entered his Final Order requiring Vepco to sign the contracts. In this Order, the Hearing Examiner expressly recognized that "the Agreements reflect negotiations and rulings based on the unique circumstances of these proceedings (including that they are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." Vepco signed the contracts on October 7 and 8, 1988. It did not appeal the SCC arbitration orders to the courts. Three of the four projects came into commercial operation in 1992. (The fourth project encountered permitting problems and has been placed in default.)

At about the same time, Vepco signed contracts resulting from its 1988 solicitation during December 1988 and January 1989. Seven of these projects came into commercial operation in 1990 and 1992. They average $171/kW in capacity payments.

Public Staff witness Powell compared the operation of the Hadson projects, which operate at a capacity factor of 27.1%, to the projects resulting from the 1988 solicitation, which operate at a capacity factory of 35.9%. The capacity costs of the Hadson projects are twice the average costs of the 1988 projects. Witness Powell recommended that the allowable capacity costs for the Hadson projects should be the average capacity costs of the 1988 package. Consequently, he recommended that $170/kW, or $1.39 million, be disallowed. On cross-examination, he testified that he was evaluating what the North Carolina ratepayers should pay and that the costs the Company seeks to recover are too high.

Company rebuttal witness Edwards testified that this Commission should accept the Hadson capacity payments as reasonable because they resulted from arbitration before the Virginia SCC and because there is no evidence of imprudence on the Company's part. He further testified that using the costs from the projects selected from the 1988 solicitation was totally inappropriate. He conceded, however, that the Company had argued before the Virginia arbitrator that the results of the 1988 solicitation (or, alternatively, the 1986 solicitation) should be used to determine the avoided costs for the Hadson projects.

The Public Staff's recommended disallowance of $1.39 million of the Hadson capacity costs raises several issues. First, the Commission must determine whether the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C.A. § 824a-3, preempts State regulatory action or otherwise binds this Commission to follow the Virginia SCC's determination of avoided costs. We conclude that it does not.

Section 210 of PURPA requires electric utilities to purchase power from qualifying cogeneration and small power production facilities (QFs). The rates for such purchases must be just and reasonable to the utility's consumers and in the public interest and they must not discriminate against QFs. PURPA provides that the rates not exceed the incremental costs of alternative electric energy, referred to in the FERC regulations as "avoided costs." 16 U.S.C.A. § 824a-3(a) and (b); 18 C.F.R. § 292.304(a) and (b) (1980). The regulations define avoided costs as the incremental costs to a utility of electric energy or capacity or both which, but for the purchase from the QF, the utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6) (1980). Energy costs are the variable costs associated with producing electricity, such as the costs of fuel. Capacity costs are the costs associated with providing the capability to deliver electricity, primarily the capital costs of facilities. The regulations set forth certain factors to be considered in determining avoided costs. 18 C.F.R. § 292.304(e) (1980).

QFs are exempt from the Federal Power Act (with a few exceptions that are not relevant here). 18 C.F.R. § 292.601(b) (1980). Implementation of the regulations dealing with regulated utilities' obligation to purchase from QFs and the rates for such purchases is left to state regulatory authorities. 18 C.F.R. § 292.401(a) (1980). Such implementation by the states may consist of issuing regulations, undertaking to resolve disputes between utilities and QFs, or any other action reasonably designed to implement the FERC regulations. In adopting its regulations, FERC noted that it

> supports the recommendation made in the Staff Discussion Paper that it should leave to the States . . . "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

Regulations Implementing § 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12214, 12226 (1980). FERC rules afford the states "great latitude"; FERC recognized that "economic and regulatory circumstances vary from State to State and utility to utility." Id. at 12230-1. FERC expressly acknowledged that its regulations are not intended to divest a state regulatory agency of its authority under state law to review contracts for purchases as part of its regulation of electric utilities. Id. at 12233.

While PURPA and the FERC regulations do not allow rates greater than avoided costs, there may be a separate basis in state law or policy for such higher rates. The Virginia SCC at one time adopted the policy of considering intangible environmental and societal benefits associated with QF power. The SCC approved a 15% rider to Vepco's avoided cost tariff for the purpose of giving reasonable weight to these benefits. PURPA does not provide for the addition of such a rider. The basis for this rider was Virginia law and policy. (This

Commission has never added a rider of this sort to its determination of avoided costs in North Carolina.) The 15% rider is no longer required in Virginia, but, as discussed below, it is clear that the arbitrator considered economic benefits unique to the State of Virginia in setting the Hadson capacity payments.

Based on the foregoing, the Commission concludes that PURPA does not preempt state action. In fact, it mandates state action and expressly leaves the states flexibility to experiment and accommodate special circumstances. Thus, "avoided costs" can be determined quite differently by different jurisdictions. Further, PURPA does not preempt this Commission's authority to review QF contracts in setting rates for the electric utilities operating in North Carolina. This Commission, in setting rates for NC Power in North Carolina, is not bound to interpret PURPA in the same manner as the Virginia SCC or to provide for the SCC's consideration of benefits unique to Virginia.

A second issue raised by the Public Staff's recommendation is whether PURPA allows avoided costs to be determined by a competitive bidding procedure. In its policy statement on competitive bidding in Case No. PUE870080, the Virginia SCC concluded that the general concept of bidding for new power supplies is a permissible response to PURPA and the FERC regulations. The SCC reasoned that if competitive negotiations are properly undertaken, the costs paid by the utility are indeed its avoided costs of not dealing with another, similarly situated QF. This Commission's review of PURPA and the FERC regulations leads us to the same conclusion. The results of a competitive bidding process may be used as the soliciting utility's avoided costs.

A third issue is whether this Commission must make a finding of management imprudence in order to disallow part of the capacity costs associated with the Hadson contracts as unreasonable. Vepco takes the position that because the Virginia arbitrator ordered Vepco to sign the contracts, the Company was not imprudent and, absent a finding of management imprudence, the costs cannot be disallowed. The Public Staff asserts that expenses can be disallowed as unreasonable for a variety of reasons and that management imprudence is only one method of demonstrating unreasonableness. The Public Staff cites State ex rel. Utilities Commission v. Carolina Power & Light Company, 320 N.C. 1, 358 S.E.2d 35 (1987)(CP&L Remand), in which the North Carolina Supreme Court explicitly rejected CP&L's argument that absent a finding of management imprudence, the Commission was required to use CP&L's actual fuel expenses when fixing rates.

G.S. 62-133(b)(3) requires that the Commission ascertain the utility's "reasonable operating expenses" when setting rates. The Commission agrees with the Public Staff that imprudence is only one method of demonstrating that a given expense is unreasonable. Therefore it is not improper to disallow prudently incurred but otherwise unreasonable expenses for ratemaking purposes.

For example, the Commission routinely adjusts expenses for abnormal weather, for unrepresentative nuclear capacity factors, and for customer growth. These adjustments have been upheld by the North Carolina appellate courts on several occasions. The case most specifically on point is the North Carolina Supreme Court's opinion in the CP&L Remand case cited by the Public Staff. This case involved the remand of a number of CP&L's general rate cases and fuel clause proceedings in the early 1980s. The remanded cases were consolidated, and several parties appealed the Commission's final order. On appeal, CP&L contended that the Commission had made no finding of management imprudence and, to the extent the Commission made findings concerning those questions, the Commission's findings were to the effect that the actions of CP&L's management were prudent. CP&L argued that "given the absence of any finding of management imprudence, the Commission was required to use CP&L's actual fuel expenses when fixing rates for the three general rate cases involved in this appeal." 310 N.C. at 11. The Supreme Court's response to this argument was: "We do not agree." Id. The Court cited State ex rel. Utilities Commission v. City of Durham, 282 N.C. 308, 193 S.E.2d 95 (1972), which involved the adjustment of test period fuel expenses to reflect substantially abnormal weather conditions. Although abnormal weather conditions are a factor clearly unrelated to management prudence, the Supreme Court found no error in the Commission's adjustment of test period expenses and revenue to take those abnormalities into account. The Court in the CP&L Remand case concluded as follows:

> Therefore, although management prudence may be an important factor considered by the Commission in a general rate case, management prudence vel non does not control the Commission's decision as to whether to adjust test period data to reflect abnormalities having a probable impact on the utility's revenues and expenses during the test period, in order that it may set reasonable rates in compliance with N.C.G.S. § 62-133.

320 N.C. at 12. The Court in fact found that the Commission had a duty to normalize or adjust expenses as necessary. Id.

The Commission's rule prohibiting the inclusion of political and promotional advertising in reasonable operating expenses is another example. Rule R12-13(a) provides in part:

> In ascertaining reasonable operating expenses pursuant to G.S. 62-133, no electric or natural gas utility shall be permitted to recover from its ratepayers any direct or indirect expenditures made by such utility for political or promotional advertising as defined in Rule R12-12 or for other nonutility advertising.

Rule R12-12(d) specifically excludes several types of advertising from the definition of political and promotional advertising. With regard to these exclusions, R12-13(c) provides that expenditures for these excluded types of advertising generally will be deemed to be reasonable operating expenses, but the Commission is not precluded from determining on a case-by-case basis the extent to which such expenditures exceed a reasonable level. Thus, while it may be prudent for utility management to engage in political and promotional advertising, the Commission's rule provides that the expenses for such advertising are unreasonable per se. Furthermore, the rule provides for the disallowance of unreasonable expenditures for other types of advertising.

Another example of the Commission determining the level of reasonable expenses without regard to the prudence of the utility's actions is our decision filed on October 12, 1992, in Docket No. W-354, Sub 111, the most recent general rate case of Carolina Water Service, Inc. (Carolina Water). In this case, the Public Staff recommended that a portion of the expenses related to Carolina Water's headquarters in Northbrook, Illinois, be disallowed. Carolina Water's rebuttal evidence was to the effect that those expenses were prudent and reasonable. The Commission concluded that the level of Northbrook expenses had increased at an unreasonable level and therefore these expenses should be adjusted to a reasonable level. No finding of imprudence was made.

Other examples can be found in the present Order. In this Order we discuss several operating expenses in terms of reasonableness without any specific discussion or finding as to prudence.

Based on the foregoing, the Commission concludes that "reasonable," as used in G.S. 62-133, does not equate to "prudently incurred" and that a prudently incurred expense can be shown to be unreasonable for numerous reasons. Accordingly, the Commission rejects the Company's argument and concludes that management imprudence need not be shown for the Hadson capacity payments, or some portion of them, to be disallowed as unreasonable.

The issue to be decided is whether the level of expense for the capacity associated with the Hadson projects is reasonable for ratemaking purposes in North Carolina. The Commission concludes that it is not.

First, we need only compare the Hadson capacity payments with other, contemporaneous measures of avoided costs. Total annual capacity payments for the three Hadson projects are over $64 million systemwide. They average $341/kW. In contrast, the seven operational projects that came out of the 1988 solicitation average $171/kW. The Virginia SCC itself said that such a solicitation is a good means of "approximating real, not theoretical, avoided costs." Vepco's 1986 solicitation produced operational projects that average $141/kW in annual capacity payments. Interestingly, the 1986 solicitation used Vepco's proposed Chesterfield 7 as a benchmark, and Vepco witness Edwards testified that "if you would publish a benchmark you'll see that most bids if not all of them will come in right at the benchmark price, and that's what we saw in the December '86 solicitation." When Chesterfield 7 was used to establish the avoided costs for the Hadson projects, it produced far higher capacity payments than when it was used as a benchmark for the 1986 solicitation. The Virginia arbitrator himself stated in a February 1990 Order that payments for the Doswell project, one of the projects from the 1986 solicitation, were based on the avoided costs of Chesterfield 7 and were reasonable. The Doswell capacity payments for this rate case are $146/kW. The Hadson payments, also based on Chesterfield 7, are $341/kW. All of this evidence tends to show that the Hadson capacity payments are out of line. The Hadson payments are also out of line with the Company's avoided costs in North Carolina. Schedule 19 sets forth this Commission's determination of Vepco's avoided costs. Schedule 19 is not directly applicable to projects the size of the Hadson projects; such large QFs must negotiate rates with the utilities. However, as a practical matter, the avoided costs set by the Commission provide a cap on negotiated rates. Based on the version of Schedule 19 approved at the time the Hadson contracts were executed, the Hadson capacity would have cost Vepco $17 million a year, rather than $64 million.

Second, it is very clear from the record in this proceeding that the SCC's treatment of the Hadson projects was directly related to expected benefits to Virginia from these projects. The arbitrator's Award and Final Order dated September 30, 1988, specifically recognizes that the Hadson contracts "reflect negotiations and rulings based on the unique circumstances of these proceedings (including that [the projects] are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." The arbitration petition for the project at The Lane Company indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result. These benefits flow to Virginia, not to North Carolina. For this reason, it may be reasonable for Virginians to pay the extra costs associated with the Hadson projects. But it is unreasonable for North Carolinians to pay such extra costs, and our responsibility is to set fair and reasonable rates for North Carolina. We cannot accept the assumption implicit in the Company's position that our authority to set rates for North Carolina -- and, by extension, the authority of the North Carolina Supreme Court -- is circumscribed by the decision of an arbitrator in Virginia.

Finally, we cannot help but note that Vepco itself argued before the Virginia arbitrator that the results of the 1988 solicitation should be used to set the capacity costs for the Hadson projects. This is exactly what the Public Staff is arguing now and the Company is opposing.

Based on the foregoing, we conclude that the capacity costs included in the arbitrated contracts for the three Hadson projects are not reasonable for ratemaking purposes in North Carolina.

In making this decision, we recognize our obligation to encourage QFs, but that is not the issue here. The issue here is ascertaining reasonable operating expenses for purposes of setting just and reasonable rates in North Carolina. We cannot find these expenses to be reasonable for our purposes when they are well over twice contemporaneous measures of avoided capacity costs and when they were clearly influenced by economic benefits unique to the State of Virginia. This Commission also recognizes the position of Vepco. It is "caught in the middle" between our decision and that of the Virginia SCC, but that is not unique to this issue. That is an inevitable consequence of doing utility business across state lines. For example, we use a different cost allocation methodology than the Virginia SCC for purposes of allocating production costs between states, and the different methodologies mean that Vepco may collect more revenues or may collect less revenues than if both states used the same methodology. The same thing can happen any time this Commission and the Virginia SCC decide the same ratemaking issue and reach different conclusions. Still, this Commission must exercise its own judgment. Neither we nor the SCC is bound by the decision of the other.

Finally, we must determine what is a reasonable level of capacity costs for the Hadson projects. Public Staff witness Powell testified that the Hadson projects should be compared to the NUG projects selected by Vepco as a result of its 1988 solicitation. He testified that there are seven operational NUG projects that were selected in the 1988 solicitation, the capacity costs for which the Company seeks to include in rates in this proceeding. These projects have a combined capacity factor of 35.9% and their average capacity cost is \$171/kW. By contrast the average capacity factor for the Hadson projects is expected to be 27.1%. Powell testified that it is appropriate to compare the costs of a NUG to the costs of other NUGs and that the 1988 projects are appropriate to use because of timeliness and similar operation to the Hadson projects. He testified that it is reasonable to expect that similar operation would yield similar capacity costs. Because the capacity costs of the Hadson projects are twice the average costs of the 1988 projects, witness Powell recommended that the allowable capacity costs for the Hadson projects should be the average capacity costs of the 1988 package. Consequently, he recommended that \$170/kW, or \$1.39 million, be disallowed.

Witness Powell also reviewed the projects that are in operation from the 1986 solicitation. Because of the time difference as to when the contracts were executed and other constraints, he did not include them in his calculation of the Public Staff's recommended capacity adjustment for the Hadson projects. His Exhibit KLP-1, however, shows that the six projects resulting from the 1986 solicitation have a combined capacity factor of 32.2% and that their average capacity cost is $141/kW. If the 1986 projects were used to adjust the $341/kW capacity costs of the Hadson projects, a disallowance of $200/kW (or $1.63 million) would be appropriate.

The Commission has already concluded that PURPA allows avoided costs to be determined through competitive bidding. While the average capacity cost for the 1986 solicitation could be used to adjust the capacity costs for the Hadson projects, the average capacity cost for the operational projects resulting from the 1988 solicitation is more appropriate. The projects resulting from the 1988 solicitation that are still active but not yet operational are not included in the average because there is no guarantee that they will become operational and no way to tell what their exact capacity costs will be until they come on line. Accordingly, NC Power's operation and maintenance expenses should be reduced by $1,390,000 to reflect the unreasonable portion of the capacity costs for the Hadson projects.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 60-74

The evidence supporting these findings of fact is included in the testimony and exhibits of Company witnesses Rhodes, Schools, Chamberlain, Edwards, and Carney and Public Staff witnesses Maness, Powell, and Hinton. The levels of operating revenue deductions (excluding fuel expense) proposed by the Company and the Public Staff representing their final positions are set forth in the following schedule:

(000's Omitted)

Item	Company	Public Staff	Difference
Operation and maintenance expense	$ 76,530	$ 75,011	$(1,519)
Depreciation and amortization	21,912	20,606	(1,306)
Other taxes	11,100	11,100	-
Income taxes	7,747	8,628	881
Charitable contributions	89	-	(89)
Other interest expense	208	208	-
Interest on tax deficiencies	171	171	-
Total operating revenue deductions	$117,757	$115,724	$(2,033)

As shown in the above schedule, the Company and the Public Staff agree on the amounts to be included in operating revenue deductions for other taxes, other interest expense, and interest on tax deficiencies. The Commission thus concludes that the levels of other taxes, other interest expense, and interest on tax deficiencies appropriate for use in this proceeding are $11,100,000, $208,000, and $171,000, respectively.

Operation and Maintenance Expense

The first area of difference between the Company and the Public Staff is operation and maintenance expense. The difference of $(1,519,000) is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Adjustment to advertising expense	$ (132)
Adjustment to purchased capacity expense	(1,390)
Removal of 50% of selected officers' compensation	(28)
Removal of cost of community and governmental affairs projects	(10)
Adjustment to common stock issuance expense	41
Total	$(1,519)

The first adjustment made by the Public Staff concerns the appropriate amount of advertising expense. The $(132,000) difference between the parties is itemized as follows:

Item	Amount
Competitive advertising	$(108,000)
Promotional advertising	(11,000)
Image advertising	(13,000)
Total difference	$(132,000)

The advertisements at issue were set forth in Public Staff Chamberlain Rebuttal Cross-Examination Exhibit No. 1. Public Staff witness Maness made an adjustment to remove $108,000 of competitive advertising costs. In calculating his adjustment, witness Maness removed 100% of the costs of the Baby, Degree, and Gas Grill advertisements and 50% of the costs of the Company's Co-Op advertising program. Witness Maness testified that it was appropriate to consider 50% of the costs of Co-Op advertising to be costs of advertising intended in whole or in part to compete with natural gas companies or with other energy providers. Witness Maness stated that it would be inappropriate to require ratepayers to support advertising which included the promotion of electricity over gas, and that he did not think this Commission should send a message to utilities that ratepayers would finance a competitive war between electric and gas companies. Witness Maness further stated that he was unaware of this Commission taking a position on the preference of either gas or electricity. Witness Maness testified that he had allowed advertising costs associated with ads that promoted the more efficient use of electricity but did not allow ads that promoted the use of electricity over gas.

The Company took the position that the purpose of this type of advertising was to promote energy efficiency and provide information to the Company's customers. On cross-examination, witness Chamberlain acknowledged that the Company is in competition for winter heating with gas companies and that the issue is the energy choice one makes. Furthermore, witness Chamberlain stated that he was unaware that the Commission had disallowed competitive advertising costs in North Carolina Natural Gas Corporation's last general rate case.

The Commission has carefully reviewed Public Staff Chamberlain Rebuttal Cross-Examination Exhibit No. 1 in regard to the competitive advertising costs in question. The Commission agrees with the Public Staff that it is proper to remove from operating revenue deductions advertising that is designed to compete with natural gas companies or with other energy providers. On the other hand, it is also proper to include in the cost of service advertising that is devoted to conservation, reduction of peak demand, and energy efficiency, all of which are permissible under Rules R12-12 and R12-13. Based on its review of the ads, the Commission finds and concludes that as many as one-half of the ads disallowed by the Public Staff for competitive advertising costs do indeed promote conservation, reduction of peak demand, and energy efficiency. Therefore, $54,000 of the Public Staff's recommended disallowance should be included in the Company's operating revenue deductions for purposes of this proceeding.

Witness Maness removed $11,000 of promotional advertising cost. Witness Maness testified that the promotional advertisements were intended to promote the sale of outdoor or night lighting and as such the costs of the ads are not a legitimate cost of providing electric service to ratepayers. Witness Chamberlain took the position that this type of advertising promotes the use of efficient residential outdoor lighting. On cross-examination, witness Chamberlain stated that he was not familiar with the Commission Rules R12-12 and R12-13 which define promotional advertising. Furthermore, witness Chamberlain acknowledged that the "promotional" ads did not provide information to customers about converting from inefficient incandescent bulbs to high efficiency bulbs nor about using motion-sensor lighting that might be less wasteful. Witness Chamberlain also testified that the National Night Out Campaign advertisements were part of the Company's public service or community activities concerning crime prevention.

Based on the foregoing and its review of the advertisements in question, the Commission concludes that the Public Staff adjustment to exclude promotional advertising costs is appropriate. The Commission finds that the Company's promotional advertising is inconsistent with the provisions setting forth the allowable types of advertising in Commission Rules R12-12 and R12-13.

The remaining difference in advertising costs relates to the Public Staff exclusion of $13,000 of image advertising costs. Witness Maness testified that it was the Public Staff's position that image advertising was not a necessary cost for public utilities and therefore those costs should be removed from operating revenue deductions.

Witness Chamberlain testified that the ads that were classified by the Public Staff as image advertising were part of an overall ad campaign to provide information and meet customer needs. When questioned about various ads, such as the sweater recycling ads, witness Chamberlain admitted that the majority of the ads did not directly address issues of safety or energy efficiency. On cross-examination concerning advertising for the Energyshare program, witness Chamberlain stated that this program was not image advertising but it was advertising consistent with the overall strategy of promoting Company name recognition.

Witness Chamberlain's position throughout his testimony was essentially that each ad was part of the campaign, and if the campaign was valid, then each part was also necessary. How NC Power reacts to its advertising agency's recommendations and how this Commission deals with the advertising costs are two entirely separate issues. The Commission will review each ad pursuant to its Rules.

After a careful review of Public Staff Chamberlain Rebuttal Cross-Examination Exhibit Nos. 1 and 2, the Commission concludes that the Public Staff adjustment is proper and consistent with the Commission's policy concerning image advertising. The Commission finds that the amount of image advertising costs to be removed from the cost of service is $13,000.

The second adjustment to operation and maintenance expense made by the Public Staff is the adjustment recommended by Public Staff witness Powell to the cost of capacity purchased from the Hadson project. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 34-59, the Commission has found this adjustment to be appropriate. Therefore, the Commission concludes that it is appropriate to reduce operation and maintenance expense by $1,390,000 to reflect the removal of unreasonable purchased capacity costs.

The next adjustment made by the Public Staff concerns officers' salaries. Public Staff witness Maness testified that consistent with the adjustments made by the Commission in recent years for other electric utilities, he was recommending an adjustment to charge the stockholder 50% of the compensation paid by the Company to those officers whose functions are most closely linked with meeting the demands of the Company's sole common stockholder, Dominion Resources, Inc. Witness Maness indicated that the officers whose compensation he split were as follows:

(1) President/Chief Executive Officer
(2) Chairman of the Board of Directors
(3) President/Chief Executive Officer of Dominion Resources, Inc.

Witness Maness testified that these three individuals are closely linked to meeting the demands of the Company's common shareholder. All three individuals serve on the Vepco Board of Directors, as well as the Dominion Resources, Inc. Board of Directors. The Chairman of the Vepco Board is also Chairman of the Dominion Resources, Inc. Board, as well as of the Boards of Dominion Resources, Inc.'s other subsidiaries, Dominion Capital, Dominion Energy, and Dominion Lands. Witness Maness testified that this adjustment is especially appropriate for Vepco given the nature of Dominion Resources, Inc.'s non-regulated business interests. Witness Maness stated that the interests of Dominion Resources, Inc. as they relate to its non-regulated businesses may not always coincide with the interests of Vepco's retail ratepayers. Witness Maness also testified that the Commission has adopted an adjustment consistent with his approach in each of the seven Duke, CP&L, and Vepco general rate cases decided since November 1984.

Company witness Schools testified that officers' compensation is an appropriate determinant of the cost of service. Witness Schools also testified that the allocation of officers' compensation between Vepco and other subsidiaries of Dominion Resources, Inc. (which, according to the testimony of witness Maness, contributed to an increase of 96% in the compensation paid by Vepco to the officers in question in this proceeding over and above that reflected in the last general rate case proceeding) is based on an Order of the Virginia State Corporation Commission. However, witness Maness pointed out that his adjustment focuses on the level of executive compensation paid by Vepco and testified that the fact that this compensation results from an allocation should not affect the evaluation of whether or not 50% of it should be assigned to the common stockholder. Witness Maness indicated that the adjustment is based on the duties that these officers perform as employees of Vepco, not as officers and employees of Dominion Resources, Inc.

After careful consideration, the Commission concludes that the Public Staff adjustment to exclude 50% of the compensation of the three officers in question is appropriate. The Commission finds that it is reasonable for the Company's common stockholder to bear 50% of the compensation expense of the Company officers whose function is most closely linked with meeting the demands of the stockholder. The Commission notes that this adjustment is consistent with adjustments made in the following 11 electric general rate cases:

Duke Power Company - Docket No. No. E-7, Subs 338, 391, 408, and 487; Carolina Power & Light Company - Docket No. E-2, Subs 444, 461, 481, 526, and 537; and, NC Power - Docket No. E-22, Subs 265 and 314.

As it did in the Company's last general rate case, the Commission rejects any contention that this adjustment is inappropriate because some or all of the compensation in question results from an allocation process between the Company, its parent, and/or the parent's other subsidiaries. It is readily apparent that the compensation allocated to Vepco is at an executive level. Consequently, for purposes of evaluating the ratemaking treatment of their Vepco compensation, these individuals should be treated as officers of Vepco. That they may also receive compensation from the parent company or its other subsidiaries on the basis of activities performed as employees of those entities is irrelevant to the question of whether a portion of their Vepco compensation should be assigned to the common stockholder on the basis of the inherent relationship between stockholders and the top executives of a utility. The Commission is making its adjustment on the basis of the relationship of Dominion Resources, Inc. to Vepco as a stockholder, not on the basis of the relationship of Dominion Resources, Inc. to Vepco as a co-employer of certain individuals. These two relationships are distinct and separate.

The next adjustment to operation and maintenance expense made by the Public Staff is its removal of the cost of community and governmental affairs projects. Public Staff witness Maness testified that these expenses fall in the category of contributions, donations, and other non-utility related items which are not a necessary cost of providing utility service. The Commission agrees that non-utility related items should not be included in cost of service and, consistent with its findings and conclusions regarding charitable contributions discussed elsewhere in this Order, concludes that the Public Staff adjustment to remove $10,000 related to community and government affairs projects from operation and maintenance expense is reasonable and appropriate.

The final Public Staff adjustment to operation and maintenance expense concerns the appropriate treatment of common stock issuance costs. As discussed in the Evidence and Conclusions for Finding of Fact No. 80, the Commission has found the adjustment recommended by Public Staff witness Hinton to be appropriate. Therefore, the Commission concludes that the Public Staff adjustment to increase operation and maintenance expense by $41,000 to reflect common stock issuance costs is reasonable and appropriate for purposes of this proceeding.

In summary, the Commission concludes that the level of operation and maintenance expense (other than fuel) under present rates appropriate for use in this proceeding is $75,065,000.

Depreciation and Amortization

The second area of difference between the Company and the Public Staff is depreciation and amortization expense. The difference consists entirely of the Public Staff adjustment to remove the North Anna Unit 3 amortization expense of $1,306,000 (as proposed by the Company) from expense. Public Staff witness Maness testified that because the amortization period established by the Commission for the North Anna Unit 3 abandonment loss will end approximately six months after the date rates become effective in this proceeding, inclusion of the remaining amortization expense in rates would result in a non-representative level of operating revenue deductions. Therefore, witness Maness removed the amortization from expenses. According to witness Maness, his recommended treatment is consistent with the treatment accorded the North Anna Unit 4 amortization by the Commission in the Company's last general rate case, Docket No. E-22, Sub 314.

However, witness Maness testified that it is reasonable in his view to provide the Company an opportunity to recover the remaining unamortized balance by another means. Therefore, he has recommended the establishment of a rider to recover this balance. This rider, based on the remaining unamortized balance of the loss, would expire one year after the date it becomes effective.

Company witness Schools testified that while the Company does not dispute the level of expenses used by witness Maness to calculate the rider, the use of such a rider is not warranted in this case. Witness Schools stated that the collection of North Anna Unit 3 costs throughout the amortization period has been through base rates, and that the final amortization is a proper component of cost of service which should be collected through base rates, not unnecessarily singled out for separate treatment. Witness Schools also testified that the Company is not aware that the Commission has routinely employed the use of riders for purposes of segregating cost recovery in base rates.

Therefore, the Commission is presented with four options regarding this cost: include the remaining amortization in the cost of service, exclude it entirely from rates, amortize it over a longer period of time, or allow recovery through a rider. The Commission concludes that complete exclusion is not fair to the Company, just as inclusion in ongoing operating revenue deductions would not be fair to ratepayers. Amortization over a longer period of time would provide recovery for the Company, but the Commission does not want to extend the amortization period beyond the ten years ordered if it can be reasonably avoided. Recovery of the remaining cost through a one-year rider provides recovery of the cost and does not necessitate a significant extension of the amortization period. The Commission thus finds that approach to be the most appropriate of the four possibilities. A rider of shorter duration which would terminate exactly at the end of the ten-year amortization period would also achieve the Commission's objectives. However, the Commission believes that a twelve-month rider is a reasonable choice in that it mitigates the immediate increase in the revenue requirement imposed upon the ratepayer relative to a shorter rider and does not significantly extend the recovery period beyond ten years.

Consistent with its decision in Docket No. E-22, Sub 314, regarding the North Anna Unit 4 amortization, the Commission concludes that the remaining partial year's amortization of the North Anna Unit 3 loss should be removed from ongoing operating revenue deductions and that recovery of the remaining loss should be accomplished through use of a one-year increment rider. The circumstances presented by this rate case are the same as those presented in Docket No. E-22, Sub 314 with regard to the North Anna Unit 4 amortization, in that it is known that the amortization period for the North Anna Unit 3 loss will end very shortly after the rates set in this proceeding go into effect. To set rates which are fair and reasonable, the Commission must strive to determine a representative level of operating revenue deductions. Because the amortization of North Anna Unit 3 ends so soon after the effective date of the rates established in this case, inclusion of the remaining cost in operating revenue deductions would clearly result in a non-representative level of operating revenue deductions.

During the hearing, the Company attempted to differentiate the North Anna Unit 3 treatment proposed by the Public Staff from the treatment accorded the North Anna Unit 4 amortization by the Commission in the Company's last general rate case, noting that the remaining North Anna Unit 4 loss was collected as an offset to a refund of excess deferred taxes (resulting in a net credit) and that the recovery was accomplished through a one-time lump-sum billing. The Commission concludes that the factors set forth by the Company do not substantively differentiate the two treatments. In both cases, the remaining partial year's amortization has been removed from ongoing operating revenue deductions and set for recovery through a special revenue mechanism. That the North Anna Unit 3 recovery is being effected over 12 months rather than one month, as was approved for North Anna Unit 4, amounts to only a matter of timing (i.e. a 12-bill rider rather than a one-bill rider). Likewise, the fact that there is no unrelated credit in this case against which to offset the recovery of the amortization is irrelevant to the question of the appropriate treatment to be given to the amortization. The combination of the excess deferred tax refund with the North Anna Unit 4 loss in the last general rate case was simply a matter of convenience. The two issues themselves were completely unrelated to each other.

Therefore, the Commission concludes that it is appropriate, for purposes of this proceeding, to remove the remaining North Anna Unit 3 loss amortization of $1,306,000 from depreciation and amortization expense. Consequently, the level of depreciation and amortization expense appropriate for use in this proceeding is $20,606,000.

The Commission also concludes that it is appropriate and reasonable to establish an increment rider in the amount of 0.066328¢/kWh, to expire one year from the date of this Order, for the purpose of allowing the Company to recover the remaining unamortized North Anna Unit 3 abandonment loss.

Income Taxes

The third area of difference between the Company and the Public Staff is income taxes. The difference of $881,000 is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Adjustment to North Carolina state income tax surcharge rate	$ (4)
Adjustments related to Public Staff adjustments in other areas	885
Total	$ 881

The first Public Staff adjustment is its adjustment to the surcharge rate to be applied to North Carolina state income taxes. Public Staff witness Maness testified that he utilized a surcharge rate of 1.5%, the average of the rates for 1993 (2%) and 1994 (1%), as opposed to the 1993 rate of 2% utilized by the Company. In his opinion, use of the average rate is appropriate because the Company does not generally file a rate case annually.

Company witness Schools testified that it is uncertain at this time whether or not the Company will file a rate case in 1993. Witness Schools characterized the Public Staff adjustment as speculative and asserted that it builds into rates an undercollection of the 1993 level of expense. According to witness Schools, the 2% rate, being known and measurable, more accurately reflects the going level in this case.

Company witness Rhodes testified that assuming a reasonable result from this case and barring unforeseen circumstances, it is unlikely that the Company would file another general rate case this year. Additionally, witness Rhodes testified that the Company's last general rate case Order was issued approximately two years ago and that the next to last general rate case occurred about seven years before that one. Witness Schools testified subsequently that the actual decision regarding whether or not to file a case this year has not yet been made and that all of the information necessary to make that decision was not yet available.

With regard to the definition of the "going level in this case," Witness Schools testified that it involved looking essentially at a one-year rate period.

During cross-examination, counsel for the Company asked Public Staff witness Maness whether the change in the rate to 1% in 1994 is a known and measurable change taking place prior to the close of the hearing. Witness Maness replied that the change is known and measurable but would not take place prior to the close of the hearing. Witness Maness compared his treatment of the surcharge to the treatment of rate case expense, in which an estimated annual level of rate case expense is set based on an estimate of the period of time lapsing between rate cases. Additionally, witness Maness testified that the surcharge adjustment should be based on current law, under which the rate will change to 1% in 1994, and not on the basis of any hypothetical actions the legislature might or might not take.

Witness Maness was also asked if it would be possible to treat the surcharge similarly to his proposed treatment for the North Anna Unit 3 amortization and establish a rider to recover all or a portion of the cost. Witness Maness testified that it would be possible, but that he considered North Anna Unit 3 to be an "exception to the rule," while the surcharge is handled in a more traditional manner. Witness Maness listed three differences between North Anna

Unit 3 and the surcharge: the Commission's rationale in developing a ten-year amortization period, the large size of the North Anna Unit 3 cost in relation to the surcharge, and the precedent established by the Commission in the Company's last general rate case.

The Commission concludes that the expense included in this case for the North Carolina state income tax surcharge should be based on an average rate of 1.5%. It is known and measurable under current law that the rate is set at 2% for 1993 and 1% for 1994. The Commission also concludes that utilization of an estimated two-year period between this case and the next general rate case is reasonable, especially given witness Rhodes' testimony and that seven years passed between the Commission's rate case Orders in Docket No. E-22, Sub 273, and in Docket No. E-22, Sub 314, and two years between the Orders in Docket No. E-22, Sub 314 and in this case. The Commission thus finds it appropriate to spread the surtax to be incurred under current law, based on the jurisdictional state income tax expense found reasonable in this case, over the estimated period of time between rate cases of two years. This methodology is consistent with that adopted by the Commission in such recent general rate cases as North Carolina Natural Gas Corporation (Docket No. G-21, Sub 293) and Duke Power Company (Docket No. E-7, Sub 487).

With regard to the Company's contention that a rider similar to the North Anna Unit 3 rider could be established for the surcharge, the Commission concludes that such a rider is not appropriate for purposes of this proceeding. The Commission has explained elsewhere in this Order that it is appropriate to remove the North Anna Unit 3 amortization from operating revenue deductions and effect its recovery through a temporary rider to be fair to both the Company and the ratepayers. Due to the relatively small size of the surcharge, it is not necessary to remove it from operating revenue deductions to set fair and reasonable rates.

The remaining Public Staff adjustments to income tax expense result from the other Public Staff adjustments to expenses as well as its recommended capital structure, cost rates, and rate base.

The Commission thus concludes based on its findings on rate base, revenues, expenses, capital structure, and cost rates that the level of income tax expense under present rates appropriate for use in this proceeding is $8,607,000.

<u>Charitable Contributions</u>

The final area of difference in operating revenue deductions between the Company and the Public Staff is charitable contributions. The difference consists solely of the Public Staff adjustment to remove the charitable contributions of $89,000 (net of tax) included by the Company in operating revenue deductions. Public Staff witness Maness testified that he removed those items specifically identified by the Company in its filing as charitable and educational donations. Witness Maness testified that contributions are not a necessary cost of providing utility service and that ratepayers should not be required to pay for contributions to charities selected by the Company rather than the ratepayers. Additionally, witness Maness testified that even if the Company's donations are not inconsistent with the public interest, they should not be passed through to the ratepayers in the price of electricity. He stated that nonregulated businesses that make donations have much less control over the price of their goods and services than does the Company.

Company witness Schools testified that the Company continues to support the inclusion of contributions as appropriate costs of service. Witness Schools testified that contributions are necessary in terms of corporate involvement in the community and being a good corporate citizen.

Under cross-examination, witness Schools agreed that he would assume that there would be a fairly wide disparity in the charities to which different ratepayers would contribute. Witness Schools also agreed that a residential ratepayer in Elizabeth City would not have the option of buying electricity from another provider if he disagreed with a charity to which the Company contributes.

Witness Schools testified that if the Company refused to make charitable contributions, it could result in ill-will which could translate into additional costs. However, he could cite no example of such ill-will or additional costs resulting from the refusal to make a particular contribution in the past. Witness Maness testified that he believed the ratepayers are interested in the provision of quality service at a reasonable cost and that by providing that, the Company can do much to maintain the goodwill felt toward it by the ratepayers.

The Commission concludes that the Company's charitable contributions should not be included in the cost of service. It has been a long-standing policy of this Commission to exclude contributions from operating expenses. Charitable contributions are not a necessary cost of providing electric service.

Therefore, the Commission concludes that the Public Staff adjustment to remove $89,000 of charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

Based upon the Commission's conclusions in this Order, the Commission finds that the level of operating revenue deductions under present rates, excluding fuel expense, appropriate for use in this proceeding is $115,757,000, calculated as follows:

(000's Omitted)

Item	Amount
Operation and maintenance expense	$ 75,065
Depreciation ~~and amortization~~	20,606
Other taxes	11,100
Income taxes	8,607
Other interest expense	208
Interest on tax deficiencies	171
Total	$115,757

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 75 AND 76

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Carney and Public Staff witness Hinton.

The Company and Public Staff are in agreement with respect to the capital structure and cost rates for long-term debt and preferred stock for use in this proceeding.

Therefore, the Commission finds and concludes that the capital structure and the cost rates for long-term debt and preferred stock appropriate for use herein are as follows:

	Capital-ization Ratio %	Cost Rate %
Long-term debt	45.227	8.024
Preferred stock	9.955	5.598
Common equity	44.818	-
Total	100.000	-

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 77-82

The evidence for these findings of fact is found in the testimony and exhibits of Company witnesses Avera and Carney and Public Staff witness Hinton.

The Company and Public Staff were not in agreement on the proper investor return requirement for common equity. Company witness Avera recommended that the Commission find 12.0% to 13.0% as the proper range for the cost of equity to the Company excluding any flotation costs. Public Staff witness Hinton recommended that the Commission adopt 11.5% as the cost of common equity for the Company in this proceeding.

In his pre-filed testimony, Company witness Avera employed three different methods in his cost of equity analysis: the constant growth DCF model, the non-constant growth DCF model, and the risk premium method.

In applying the constant growth DCF model, witness Avera studied 19 companies which he believed were comparable in risk to Dominion Resources, Inc., the parent holding company of Vepco. Using the constant growth DCF model, witness Avera determined that the investor return requirement was in the range of 8.9% to 12.22% for Dominion Resources, Inc. and 9.0% to 10.0% for the comparable group. Employing the non-constant growth DCF model, witness Avera estimated that the cost of equity for Dominion Resources, Inc. ranges from 6.82% to 12.69% and the cost of equity for the comparable group ranges from 8.38% to 12.46%. However, because in witness Avera's judgment the DCF method was producing illogical and unreliable results which violated the risk/return tradeoff, he testified that the results of these models could not always be relied on as a measure of investors' required rate of return.

In conducting his risk premium analysis, witness Avera surveyed the literature and selected published studies which applied seven different analytical approaches. These approaches in general can be categorized as "mechanistic" DCF-derived comparisons, investor surveys, and historical earned returns comparisons. The various studies produced cost of common equity ranges of 11.60% to 15.37% and an average risk premium result of 13.57%.

Witness Avera testified that in his opinion 25 basis points should be added to the "barebones" cost of equity to adjust for flotation costs necessarily incurred when issuing common stock. His final recommendation to the Commission was a range of equity cost rates from 12.25% to 13.25% including this adjustment.

Public Staff witness Hinton employed two different cost of equity methods in his analysis of the investor return requirement for the Company. The first method witness Hinton employed was the constant growth DCF model. He performed a DCF analysis on Dominion Resources, Inc. and on two groups of utilities comparable in risk to Dominion Resources, Inc.--an electric utilities group and a non-electric utilities group. At the hearing, witness Hinton updated his DCF results. However, his conclusion for the cost of equity based upon the DCF results remained at 11.0% to 11.5%.

Witness Hinton also performed a risk premium study based upon a study performed at the Federal Energy Regulatory Commission (FERC). In his testimony he pointed out the advantages of the FERC approach and noted several criticisms of conventional applications of the risk premium method such as the use of historical data on earned returns dating back to 1926, the use of study results based solely on polling utility stock analysts, and reliance on risk premium studies which themselves display inconclusive and wide ranging results. Witness Hinton's risk premium study, which he updated at the hearing, indicated the Company's cost of equity to be in the range of 11.3% to 12.0%.

Witness Hinton testified that, in reaching his final cost of equity recommendation, he placed more emphasis on his DCF analysis than his risk premium analysis. He concluded that the current investor return requirement to the Company was in the range of 11.0% to 12.0% and recommended that the Commission adopt 11.50% as the investor required return on equity for the Company. Witness Hinton testified that, without evidence of any test year flotation costs associated with a public offering of its common stock and with no evidence of immediate plans of the Company to make such an offering, he could not recommend an adjustment to the return on equity for flotation costs. However, in view of the actual test year expenses associated with the Company's employee and customer stock purchase plans, which were provided by the Company, witness Hinton recommended an adjustment to the cost of service to reflect this ongoing level of expense.

In his pre-filed testimony, witness Hinton also reviewed the testimony of Company witness Avera. Witness Hinton replicated witness Avera's correlation analysis and stated that he disagreed with witness Avera's conclusion that the DCF model has stopped producing logical and reliable results.

Witness Avera also filed rebuttal testimony in this proceeding. In his rebuttal testimony, he criticized witness Hinton's use of the constant growth DCF model. Witness Avera contended that the current depressed state of the U.S. economy warranted the use of a non-conventional long run growth rate of 5.8%, which produced cost of equity estimates of 12.2% and 12.5% for Dominion Resources, Inc. and his comparable group of electric utilities, respectively. Second, witness Avera sought to rebut witness Hinton's approach to adjustment of risk premiums for changes in interest rates. Witness Avera criticized the Public Staff for understating the interest rate relationship and for what he said was an improper application of the risk premium method. Third, he criticized witness Hinton's failure to adjust his return recommendation for historical issuance costs. Witness Avera asserted that the true flotation cost adjustment was 25 basis points. Finally, he criticized witness Hinton's failure to account for purchase power commitments in his pre-tax coverage ratio calculations. He contended that if witness Hinton had accounted for the view financial ratings agencies have of purchased power debt equivalents, his return on equity would only produce interest coverage ratios sufficient to support a triple-B bond rating.

During cross-examination, Company witness Avera was questioned on the calculated return on equity derived from his version of the non-constant growth DCF model. Witness Avera maintained that he considered some of the results from the general form DCF to be patently unreasonable. Witness Avera also acknowledged that the results of his non-constant growth DCF varied over a wide range for both Dominion Resources, Inc. and for his comparable companies. Upon further cross-examination, witness Avera acknowledged that the Commission, on page 62 of its Final Order in Docket No. E-22, Sub 314, was correct in its characterization that "the results from the non-constant growth DCF are simply too volatile."

Witness Avera was also cross-examined extensively on his application of the risk premium method in this case. In response, he testified that the risk premium method does not provide a precise return on equity result. He acknowledged the Order for the prior NC Power rate case in 1991, Docket No. E-22, Sub 314, and the Federal Communications Commission's Order in 1991 which accepted neither his risk premium methodology nor his empirical DCF correlation study.

During cross-examination, witness Avera acknowledged several apparent inconsistencies in and between the risk premium studies which he employed. He acknowledged that Brigham, Shone & Vinson concluded:

> Risk Premiums like interest rates and stock prices are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched to current interest rates.

The Brigham, Shone & Vinson study also reported finding a significantly positive correlation of interest rates and risk premiums in one period and a negative correlation in another period. Upon further cross-examination, witness Avera acknowledged the findings of another study by Carleton, Chambers and Lakonishok which concluded:

> Using two models, which assume alternative expectations as to the outcome of rate of return regulation, we are unable to find a significant relationship between risk premiums and interest rates.

In his pre-filed testimony, witness Avera cited a risk premium study conducted by Charles A. Benore of the investment advisory firm of Paine Webber, Mitchell Hutchins, Inc. Witness Avera reported this study determined that utility equity risk premiums averaged 4.24% over double-A utility debt costs. He agreed that the Benore study cited in his pre-filed testimony reported that the risk premium for an electric utility not involved in nuclear construction was approximately 3.17% in 1984 and 2.65% in 1985. On rebuttal cross-examination, witness Avera recalculated the risk premium result of the Benore study with the equity risk premiums of utilities without nuclear construction from the 1984 and 1985 surveys which he reported only marginally reduced the 12 year average equity risk premium from 4.24% to 4.06%. He also acknowledged that Vepco is not currently in the process of building a nuclear power plant.

With respect to his flotation cost adjustment of 25 basis points, witness Avera stated that this adjustment was proper even though the Company has not incurred any flotation costs in seven years and does not plan to incur any flotation costs in the foreseeable future.

On rebuttal, Company witness Carney was extensively cross-examined regarding the reasonableness of witness Avera's 25 basis point flotation cost adjustment to reflect the ongoing level of carrying costs associated with unrecovered past common equity issuance expenses. Attorney General Avera Rebuttal Cross-Examination Exhibit No. 2 showed that a 25 basis point adjustment to the Company's return on equity would, on a system-wide basis, result in increased revenues of approximately $15.8 million to the Company. Witness Carney acknowledged that in the last NC Power rate case the Commission awarded a 0.02% increase in the cost of equity to recover a representative level of common equity flotation costs.

Public Staff witness Hinton was cross-examined extensively on the assumptions used in deriving the constant growth DCF model and its relationship to the non-constant growth DCF model. He stated that the difference in the two models was that the non-constant growth model required an estimate of the stock price at a particular point in time whereas the constant growth DCF required an estimate of the growth rate in dividends to infinity. Witness Hinton stated that it is very difficult to predict a stock price at a certain point in the future due to the daily market changes and that this aspect of the non-constant growth model increases the method's difficulty and unreliability.

Witness Hinton also answered several questions concerning the risk premium method in general. He testified that the historical risk premium approach can be easily manipulated depending on the time period selected. Upon cross-examination, he responded that the risk premiums studies used by witness Avera demonstrated inconclusive results, especially in the manner in which risk premiums and interest rates are related. He pointed out that some studies report a positive relationship while others report a negative relationship. He further testified that an obvious bias exists when a study utilizes a poll of stock analysts who also perform roles in selling or issuing that very common stock.

Witness Hinton pointed out several distinct advantages of the FERC approach in calculating a risk premium result over other risk premium studies, including the contemporaneous comparison of debt cost and equity costs specific to each utility, the use of current risk premiums over historical risk premiums, and the ability to observe the actual data used. During cross-examination, witness Hinton was asked several questions regarding his use of the FERC risk premium study which compares a utility's authorized returns on equity with its bond cost. He testified that the intent of the study was to measure the additional rate of return investors require to invest in a given utility's equity over its bonds. He was also cross-examined on the bond cost calculation for the Company. He testified that the bond cost calculation was in accord with the FERC study and that, at the time he filed the testimony, the bond cost calculation for the Company was equal to the 8.6% yield on the A-rated bond index for November 1992, as reported in Moody's Bond Survey.

Witness Hinton also stated that, in view of the inherent problems associated with any cost of equity method that is largely dependent on bond yields, he gave more emphasis to, and had more confidence in, his DCF results. He testified that today's economic environment differs significantly from prior years, and the lower current DCF results indicate that investors are requiring a lower equity return for utility investments.

The determination of the fair rate of return for the Company is of great importance and must be made with great care because the return allowed will have an immediate impact on the Company, its stockholders, and its customers. In the final analysis, the determination of a fair rate of return must be made by this Commission using its own impartial judgment and guided by the testimony of expert witnesses and other evidence of record. Whatever return is allowed, it must balance the interests of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4)

> ...as will enable the public utility by sound management to produce a fair profit for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and its existing investors.

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b)

> ...supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States.

State ex rel. Utilities Comm. v. Duke Power Co., 285 N.C. 377, 388, 206 S.E. 2d 269, 276 (1974).

The Commission is mindful that its conclusion of the appropriate rate of return must be based upon specific findings showing what effect it gave to particular factors in reaching its decision. State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 699, 370 S.E. 2d 567, 573 (1988). Based upon the evidence in the record, the Commission concludes:

(1) The proper capital cost rates are 8.024% and 5.598% for long-term debt and preferred stock, respectively. The Company and Public Staff agreed that these cost rates are proper to employ in conjunction with the Company's September 30, 1992, capital structure. The Commission agrees with the Public Staff and the Company that these cost rates are proper to employ for purposes of this proceeding.

(2) Company witness Avera's version of the general form DCF model and risk premium method as applied in this case should be accorded only minimal weight for purposes of this proceeding. The results calculated from the non-constant growth DCF model are simply too volatile. The Commission also notes that witness Avera testified that "the general form DCF should not be heavily relied on."

The risk premium method as applied by witness Avera in this case is too easily manipulated. Evidence in the record showed there was a specific risk premium difference between utilities with and without nuclear construction programs. His pre-filed testimony failed to consider this risk premium difference and the Commission is not convinced that his adjustment to reflect nuclear construction programs is adequate or proper. Witness Avera's historical risk premium analysis also failed to consider that current economic conditions are vastly different from the economic conditions that prevailed from 1926 to 1987. The Commission also finds that minimal weight should be accorded to his risk premium results because the academic studies used to determine the relationship of interest rates and risk premiums are inconclusive.

Evidence was presented that other regulatory agencies have rejected the use of the risk premium studies cited by witness Avera as supporting his cost of equity recommendation. The Commission dealt with this issue in the February 14, 1991, Order in the last NC Power case, Docket No. E-22, Sub 314, and now reaches the same conclusion: that minimal weight should be given to witness Avera's general form DCF and his risk premium methods.

Witness Avera's pre-filed constant growth DCF conclusions ranged from 8.9% to 10.4% for Dominion Resources, Inc. and between 9.0% and 10.0% for his comparable group. He also filed rebuttal testimony that presented a revised constant growth DCF model that combined a long-term growth adjustment for the U.S. economy and a growth adjustment for the Company, which produced cost of equity estimates of 12.2% and 12.7%.

The Commission is not convinced that the current state of the economy warrants incorporating two growth factors in the constant growth DCF. Therefore, the Commission gives minimal weight to witness Avera's non-conventional DCF growth adjustment.

(3) <u>The constant growth DCF model and the FERC risk premium approach as employed by witness Hinton should be given the greatest weight for purposes of determining the cost of equity capital in this case.</u> Public Staff witness Hinton employed the constant growth DCF model which produced a cost of equity recommendation in the range of 11.0% to 11.5%.

The Commission does not agree with witness Avera's assertion that a stock's earnings, dividends, and book value must grow in lock-step for the constant-growth DCF model to be valid and useful for ratemaking purposes. Although the estimation of the prospective growth for these rates is necessarily problematic and requires a certain amount of subjective judgment, it appears to the Commission that witness Avera's non-constant growth DCF model is far more subjective.

Public Staff witness Hinton also utilized the FERC risk premium approach, which produced cost of equity estimates for Dominion Resources, Inc. in the range of 11.3% to 12.0%, based on a risk premium range of 280 to 350 basis points. The Commission finds no reason to believe that the required risk premium for the Company is in the significantly higher range recommended by witness Avera. The Commission further notes that, based upon the last NC Power Order, the FERC risk premium result was 2.86%, which is within the risk premium range recommended by witness Hinton.

The Commission notes that the FERC approach focuses on investors' required returns on electric utility investment, as opposed to the conventional risk premium methods that analyze earned returns during economic conditions not comparable with today. The Commission, for purposes of this proceeding, finds that the constant growth DCF model and the FERC risk premium approach produce consistent, reasonable, and reliable estimates of the cost of equity and that these methodologies should be given the greatest weight for purposes of determining the cost of equity in this proceeding.

(4) The investor return requirement to the Company is 11.8%. In reaching this conclusion, the Commission has placed the greatest weight on estimates of the cost of common equity derived by use of Mr. Hinton's constant growth DCF model and, in particular, the FERC risk premium approach. Based upon those studies, Public Staff witness Hinton testified that the current investor return requirement to the Company is in the range of 11% to 12%. We conclude that a rate of return on common equity of 11.8%, which is well within the range testified to by Public Staff witness Hinton, is reasonable and appropriate in this case. In deciding to authorize a rate of return of 11.8% on common equity, the Commission has placed slightly greater weight and emphasis on the FERC risk premium approach than the constant growth DCF results. Only minimal weight has been accorded the evidence relating to the risk premium methods and the non-constant growth DCF model contained in the Company's testimony. Based upon the entire evidence of record, the Commission finds and concludes that the proper common equity investor return requirement for purposes of this proceeding is 11.8%.

(5) The adjustment to allow the Company to recover test year common equity issuance expenses associated with the Company's stock purchase plans, as recommended by Public Staff witness Hinton, is appropriate. This adjustment will allow the Company to recover a reasonable and representative test year level of issuance expenses for common equity for reasons stated by witness Hinton. This inclusion of issuance expenses in the test-year cost of service reflects an ongoing level of expenses associated with the Company's employee and customer stock purchase plans.

The Commission rejects witness Avera's 25 basis point flotation cost adjustment to the cost of equity and finds no support for witness Carney's testimony that the Company has never collected past flotation costs. The Commission finds witness Avera's 25 basis point recommendation to be excessive and without support in the evidence of record, a factor of particular importance in view of the Supreme Court's holding that such evidence is essential. State ex rel. Utilities Commission v. Public Staff, 331 N.C. 215, 415 S.E. 2d 354 (1992). The Commission finds that the Company has incurred a fairly constant level of common stock issuance expenses for over seven years and concludes that the recommendation by witness Hinton is reasonable and supported by evidence of record.

(6) The overall fair rate of return which the Company should be allowed the opportunity to earn on its rate base is 9.48%. Based upon the Commission's findings with respect to the proper capital structure and the appropriate cost rates for each component of capital reflected in the capital structure, the Commission finds and concludes that the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 9.48%.

The Commission has also considered the question of the treatment of purchase power agreements as debt and the consequent potential risk to the bond rating of the Company. The Commission notes that its role is not that of a rating agency and that it must consider factors other than those considered by these agencies. The question of the proper treatment of these agreements is by no means closed. The Commission believes that as experience is gained, the various rating agencies may reconsider their treatment of these agreements. The Commission concludes that for purposes of regulation, these agreements should not be considered debt equivalents and that the interest rate coverage resulting from our decision in this matter is adequate. In this regard the Commission agrees with the decision of the California Public Utilities Commission in re Application of Pacific Gas and Electric Company, Decision No. 92-11-047, which contains an extensive analysis of this issue. The Commission also notes that in his December 20, 1991, letter, Thomas E. Capps, President and Chief Executive Officer of Dominion Resources, Inc., argues that the net financial risk to the Company has not been increased by its purchased power program and that a procedure for full and timely recovery through rates is in place and working well.

It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts, and to appraise conflicting evidence. State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E. 2d 786 (1982); Commissioner of Insurance v. North Carolina Rate Bureau, 300 N.C. 381, 269 S.E. 2d 547 (1980). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not res judicata in succeeding cases. State ex rel. Utilities Commission v. Duke Power Company, 285 N.C. 377, 395, 206 S.E. 2d 269, 281 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations that vary from case to case." State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 697, 370 S.E. 2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented and its weight and credibility in each case.

The Commission cannot guarantee that NC Power will, in fact, achieve the levels of return on rate base and common equity found to be just and reasonable in this Order. Indeed, the Commission would not guarantee the authorized rate of return even if it could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds and concludes that the rate of return approved in this Order will afford the Company a reasonable opportunity to earn a reasonable return for its stockholder while providing adequate and economical service to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The Commission has previously discussed its findings and conclusions regarding the fair rate of return which the Company should be afforded an opportunity to earn.

The following schedules summarize the gross revenue (excluding fuel revenue) and the rate of return which the Company should have a reasonable opportunity to achieve based upon the Commission's decisions in this case. These schedules, illustrating the Company's gross revenue requirement (excluding fuel revenue), incorporate the findings and conclusions made by the Commission. As reflected in Schedule I, the Company should be authorized to increase its annual level of non-fuel revenue by $10,642,000 based upon the adjusted test year level of operations.

SCHEDULE I
NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF OPERATING INCOME[3]
Twelve Months Ended December 31, 1991
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Operating revenue	$144,377	$ 10,642	$155,019
Operating revenue deductions:			
Operation & maintenance expense	75,065	30	75,095
Depreciation & amortization	20,606	-	20,606
Other taxes	11,100	342	11,442
Income taxes	8,607	4,038	12,645
Interest on customer deposits	208	-	208
Interest on tax deficiencies	171	-	171
Total operating revenue deductions	$115,757	$ 4,410	$120,167
Net operating income	$ 28,620	$ 6,232	$ 34,852

[3] As noted elsewhere herein, this schedule does not reflect fuel revenues and associated-fuel expenses. Based upon the test-year level of operations, the proper level of fuel revenue and fuel-related expenses for use herein, after giving effect to the Commission's approved increase, is $30,007,000 (including gross receipts tax).

SCHEDULE II
NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1991
(000's Omitted)

Item	Amount
Investment in electric plant:	
Electric plant in service including nuclear fuel	$598,046
Accumulated depreciation	(166,889)
Accumulated amortization of nuclear fuel	(36,842)
Accumulated deferred income taxes	(37,101)
Net investment in electric plant	357,214
Allowance for working capital:	
Materials and supplies	13,090
Cash working capital	(2,458)
Total allowance for working capital	10,632
Other cost-free capital	(15)
Rate base	$367,831
Rates of Return:	
Present rates	7.78%
Approved rates	9.48%

SCHEDULE III
NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1991
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
	Present Rates - Original Cost Rate Base			
Long-term debt	45.227%	$166,359	8.024%	$13,349
Preferred stock	9.955%	36,618	5.598%	2,050
Common equity	44.818%	164,854	8.020%	13,221
Total	100.000%	$367,831	-	$28,620
	Approved Rates - Original Cost Rate Base			
Long-term debt	45.227%	$166,359	8.024%	$13,349
Preferred stock	9.955%	36,618	5.598%	2,050
Common equity	44.818%	164,854	11.800%	19,453
Total	100.000%	$367,831	-	$34,852

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 84

Company witness Evans recommended that the basic revenue increase should be spread among the individual customer classes in such a way that the individual class rates of return move toward plus or minus 10% of the overall jurisdictional rate of return. He recommended that the Small General Service (SGS) class and the Outdoor Lighting Service (LITE) class be increased at the overall rate of increase. He recommended that the Residential Service (RES) class be increased approximately 1.2 times the overall rate of increase in order to move its low rate of return up closer to the overall rate of return. He also recommended that the Large General Service (LGS) class and the Traffic Lighting Service (Traffic) class receive the remaining revenue increase in order to move their high rates of return down closer to the overall rate of return. The Commission estimates that the resulting increase for the LGS class and the Traffic class would be less than 0.8 times the overall rate of return.

Public Staff witness Turner recommended that the RES class should be increased approximately 1.07 times the overall rate of increase; that the SGS class should be increased approximately 0.9 times the overall rate of increase; that the LGS class should be increased approximately 0.98 times the overall rate of increase; that the LITE class should be increased approximately 0.53 times the overall rate of increase; and that the Traffic class should be increased approximately 0.92 times the overall rate of increase. The Public Staff presented a schedule of rate increases and rates of return based on the SWPA cost allocation method which indicated that its proposed rate of increase for each class would produce a rate of return for each class that is closer to the overall rate of return.

CIGFUR witness Phillips recommended that the maximum increase allowed by the Commission for the LGS class should be the rate of increase proposed for the LGS class by NC Power even if the SWPA cost allocation method is adopted. He also recommended that if the SWPA method is adopted, approximately $810,000 additional revenues should be shifted from the LGS class to the RES class in order to account for non-symmetrical treatment of fuel costs versus fixed costs in the allocation process.

CUCA recommended that the rates of increase for each customer class be sufficient to move the rates of return for each class at least one-third of the way toward equal rates of return, provided no class receives more than a 20% increase.

The Commission estimates that increasing the RES class by 1.125 times the overall rate of increase will move the RES class rate of return approximately one-fourth of the way toward equalized rates of return. The Commission also estimates that increasing the LGS class by 0.875 times the overall rate of increase will move the LGS class rate of return approximately one fourth of the way toward equalized rates of return. The estimates are based on rates of return produced by the SWPA allocation method.

The Commission concludes that the RES class should be increased 1.125 times the overall rate of increase, the LGS class should be increased 0.875 times the overall rate of increase, and the remaining classes should be increased 1.0 times the overall rate of increase. Such increases will produce rates of return for each rate class respectively that are within 10% plus or minus of the overall rate of return, and they will produce rates of return for each rate class respectively that are closer to equalized rates of return than they were before the increases.

The per books cost of service study (SWPA method) by NC Power indicated that the rate of return for the Traffic class was considerably higher than the overall rate of return, whereas the comparable study based on adjusted revenues and expenses presented by the Public Staff indicated that the rate of return for the Traffic class was approximately the same as the overall rate of return. The Traffic class is a new class established in this proceeding, and the total revenues and expenses attributable to the class are so small that the various accounting adjustments made in this proceeding could have a disproportionate impact on the cost of service study results for the Traffic class. Therefore, out of an abundance of caution, the Commission chooses to increase the Traffic class at 1.0 times the overall rate of increase.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 85

The evidence for this finding of fact is found in the testimony of Company witness Evans and Public Staff witness Turner. The Company proposed to increase the current residential summer/winter rate differential to 1.0¢/kWh from 0.51¢/kWh, and has based its proposal on the results of a study using forecasted summer and winter peak loads and the Company's capacity expansion model and long-range planning model. The Company's study supports a summer/winter rate differential of 1.9¢/kWh.

Public Staff witness Turner stated that pricing in North Carolina should be based on an embedded cost-of-service study and that North Carolina is required to base the revenue requirement on a historical test year. He contended that forecasted information is by definition not accurate, and he pointed out that the Company's study supporting the 1.9¢ summer/winter rate differential is based on forecasted summer and winter peaks and on future-looking econometric models. He recommended that the Commission hold the rate differential at its current level until the Company submits an embedded cost-of-service study that differentiates costs between the summer and non-summer periods. In addition, he recommended that any such study should also show seasonal cost differentials for both residential and nonresidential customer classes since the Company has summer/winter rate differentials for its non-residential rate schedules also.

Company witness Evans testified that the summer/winter rate differential had been an effective tool in controlling the residential and system summer peak loads and thereby reducing additional generation requirements. He stated that the summer/winter rate differential strategy is a significant reason why the gap between the Company's summer and winter peak loads is narrowing, and that the narrowing gap results in a more efficient generation system with lower overall customer rates.

Witness Evans testified that he had no dispute with the Public Staff position that revenue requirements in North Carolina should be based on an embedded cost of service study for a historical test period. Nevertheless, he disagreed that individual rate structures should always reflect embedded cost characteristics. He indicated that projected future peak loads are critical from a resource planning perspective, and that such projected future loads should be reflected in the summer/winter rate differentials.

Witness Evans agreed that the Company should address the summer/winter rate differentials for non-residential customers as well as for residential customers. However, the Company elected to focus on the seasonal rate differential for the residential class of customers in this proceeding because it is the most weather sensitive class and presents the greatest opportunity to achieve load management objectives through seasonal pricing. He also testified that it is unlikely that an embedded cost study of seasonal differences in costs would support the proposed summer/winter differentials.

The Commission concludes that the 1.0¢/kWh summer/winter rate differential for residential customers should be approved. The differential seems to achieve generally accepted load management objectives, and it is based on a detailed study performed by the Company, although not an embedded cost study. The Commission anticipates that the Company will perform comparable studies of seasonal cost differentials for non-residential customers for presentation in future proceedings, and that such studies will be at least as detailed as the current ones.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 86

Public Staff witness Turner recommended moving the basic customer charge for residential service closer to actual cost, offset by a corresponding reduction in the energy charge for the service. The Company did not oppose his recommendation, and no other party addressed the proposal.

Witness Turner stated that the basic customer charge proposed by the Company is significantly below cost and should be increased in such a manner as to bring the charge closer to cost. The Company proposed to increase the basic customer charge to $8.50 per month from $7.16. Its cost-of-service study indicates the basic customer charge should be within a range of $15.40 to $15.60 per month based on the Company's proposed rates. Witness Turner recommended that the customer charge be increased to $9.50 per month.

Based on the Company's proposed rates, a typical residential customer with usage of 1,000 kWh per month will have an average percentage increase of 18.47% during the summer and 13.41% during the winter if the per month basic customer charge is raised to $9.50 as proposed by the Public Staff. In comparison, the percentage change for the typical customer based on the basic customer charge of $8.50 as proposed by the Company would be 18.52% and 13.5% during the summer and winter periods, respectively.

Based on the foregoing evidence, the Commission concludes that the residential basic customer charge should be increased to $9.50 per month.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 87-91

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans. Witness Evans testified that the embedded cost of distribution plant is approximately $916 per residential customer, and that the $916 per customer is reflected in current residential rates. However, the Company is currently investing approximately $2,103 per residential customer in new distribution plant for new residential customers, which results in approximately $1.8 million per year additional plant investment which must be absorbed by all residential customers, not just new customers.

Witness Evans testified that the proposed new line extension plan will require up-front payments for new residential services more frequently. The new plan will continue to require up-front payments for new non-residential services, and such up-front payments will also be more frequent. He estimated that the new plan will recover approximately $1 million per year more from new residential customers and approximately $75,000 per year more from new non-residential customers.

Witness Evans testified that the proposed new line extension plan will continue to require up-front payments from new customers based on a revenue test, but that criteria for the revenue test would be revised in various ways in order to allow a more complete recovery of the investment required for new distribution plant. The more complete recovery of investment in new plant would help delay future general rate increases. He also indicated that the proposed new plan would have some influence over the choice of energy suppliers by prospective customers, but insisted that the plan was not designed to promote one energy source over another.

Witness Evans described the transition process from the current line extension plan to the proposed new plan, and indicated that the Company was requesting 90 days after approval of the plan before making the revisions effective in order to have time to inform its customers of the changes in the plan.

No party to the proceeding opposed the proposed new line extension plan. However, the Company stipulated with the Public Staff during the hearing on revised language for the line extension plan that would permit a residential customer to request overhead construction rather than underground construction, and that would permit costs for the line extension being determined based on overhead construction costs rather than the more expensive underground construction costs. The Commission is aware that underground line extensions are currently the preferred method of construction for most new residential dwellings; however, overhead line extensions were recognized as the standard method of service connections for many years.

The Commission is of the opinion that the proposal by the Company to recognize underground construction costs coupled with a revenue test applied to these construction costs is an acceptable method of ensuring that the specific costs imposed by new customers on the system are compatible with the revenue contribution these customers are making to the system. Nevertheless, the Commission finds it appropriate for customers who so desire to continue to receive overhead line extensions, and for the construction costs applied in these instances to the corresponding revenue credit to be determined on a case-specific basis. This determination is consistent with the language agreed to by the Company and the Public Staff and introduced as evidence during the cross-examination of Company witness Evans in this proceeding.

The Commission concludes that the proposed new Line Extension Plan, as modified during the hearing, is appropriate and should be approved to become effective 90 days after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 92-95

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness McLawhorn.

Witness McLawhorn testified that the Company should upgrade the thermal standards used to qualify new residential customers for the Residential Conservation Reduction (RCR) so that the benefits derived over and above the requirements of the new North Carolina Building Code to be effective April 15, 1993, are similar to the benefits derived currently. Witness McLawhorn stated that without these changes, new customers would be receiving a rate discount for merely doing what is required by law. Company witness Evans agreed and indicated that the Company would be filing updated standards for Commission approval prior to the effective date of the new building code.

The Commission recognizes the benefits to be derived from DSM programs which ensure a greater level of energy efficiency; however, any incentives paid by the utility to its customers for participation in these programs should be commensurate with the level of benefits received. Therefore, the Commission is of the opinion that the RCR standards applied to new customers should be upgraded so that the benefits over the new building code requirements are maintained at a level comparable to the current benefits.

To this end, the Company should file revised standards before the April 15, 1993, effective date of the new code for Commission approval as agreed to by witness Evans. This filing should include a comparison of the current standards versus the current building code with the new revised standards versus the new building code, along with a quantification of the resulting benefits in each case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 96

The evidence for this finding of fact is found in the testimony of Company witness Evans and CIGFUR witness Phillips.

Witness Evans testified that since the introduction of Schedule 6C, the Company has implemented several provisions to assist the customer in participating in this program. For example, the Company has implemented a provision to allow one curtailment request per season to be excluded in determining compliance (i.e., one waiver per season); the time period from notification until the customer must reduce load has been extended from 10 minutes to 30 minutes; and the potential curtailment period in the summer was reduced from a 12-hour window to a 7-hour window, while in the winter, this window was reduced from 16 hours to one of two five-hour windows (or a total of 5 hours per day). He testified however, that for the Company to offer a cost-effective curtailable rate, the program must be designed with provisions that provide comparable value to a supply-side option. Often the peak hour in the winter occurs in the morning, but there is also need for load management in the late afternoon and early evening hours on extreme weather days. The curtailable rate must include both five-hour windows (for a total of 10 hours per day) if the rate is to be cost effective. A supply-side option such as a combustion turbine would be available to meet both the morning and afternoon peaks.

Witness Evans noted that if the Company elects to request a curtailment in both the morning and the afternoon of the same day, each curtailment will count as a separate request toward the maximum allowable 13 requests per winter season. Accordingly, he stated, this provision would not be overly burdensome to the customer, yet would provide the Company with the means to best manage its seasonal peaks and provide for a cost-effective demand-side program.

CIGFUR witness Phillips opposed the change and recommended that the Commission reject it. He stated that a customer should not be obligated to more than one curtailment per day, consistent with past practice. In his opinion, the proposal would be overly burdensome and disruptive to customer operations and should not be allowed.

The Commission concludes that the proposed change is reasonable and should not be overly burdensome on customers. The Commission is mindful of the fact that these are voluntary rates, and that the Company has already made a number of modifications to the rates to resolve past difficulties. Therefore, the Commission concludes that the proposed modification to rate Schedule 6C, Schedule SG, and Schedule CS to allow the Company to request two curtailments per day during the winter season is appropriate and should be allowed.

The Commission is also of the opinion that the Company should file a report with the Commission approximately 12 months after the date of this Order describing the number of customers added and lost from the curtailable rates described herein since the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 97

In addition to the specific modifications discussed elsewhere herein, the Company proposes various miscellaneous rate changes, administrative changes and clarifications in its rate schedules which are unopposed by any party.

Highlights of such changes include the following:

(a) Add new rate schedule 5C for cotton gin service;

(b) Add new rate schedule 30T for traffic light service and delete traffic lights from municipal rate schedule 30;

(c) Add Christmas Eve as an off-peak holiday on all TOU rate schedules;

(d) Revise the definition of on-peak hours applicable to Power Supply Demand on TOU rate schedules 5P and 6P;

(e) Revise the SEER rating for heat pumps from 8.7 to 10.0 in order for multi-family or single family homes to qualify for the Residential Conservation Reduction; and

(f) Add provisions allowing installation of new mercury vapor lighting for government facilities.

The Commission concludes that the rate schedules proposed by the Company are reasonable and should be approved as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 98 AND 99

The evidence for this finding of fact is found in the testimony of Company witness Evans and Public Staff witness Turner. The Company proposed to change the conditions under which it will deliver electric service. Currently, the Company reserves the right to require the applicant to establish that he is the owner or bona fide lessee of the premises and to execute an application for service or the most current "Agreement for the Purchase of Electricity" on file with the Commission. The change proposed by the Company would require all owners and bona fide lessees to apply jointly for service. Witness Turner recommended that no change be made in the current requirement.

Witness Turner expressed the opinion that the proposal is an unduly cumbersome method of receiving applications for electric service and goes beyond usual conditions for service. He further stated that, while the purpose of the revision is to provide the Company with an additional resource in recovering unpaid bills, the Company did not support the proposal with documentation showing the magnitude of the problem nor does it state the conditions under which the Company would impose this requirement. As the language stands, it would be left as a discretionary decision of the Company. He stated his opinion that the Company's present requirement for customer identification and a deposit is sufficient.

On cross-examination, witness Evans stated the Company would not contest the Public Staff's opposition and would withdraw the proposed change at this time. Based on the foregoing evidence, the Commission concludes that the changes proposed by the Company to paragraph II.A.1 of the Company's Terms and Conditions for the delivery of electric service rules and regulations should not be approved.

In addition to the specific modifications discussed elsewhere herein, the Company proposes various miscellaneous rate changes, administrative changes and clarifications in its terms and conditions of service which are unopposed by any party.

Highlights of such changes include revised service charges as follows:

Service connections	From $23.74 to $20.55
Bad check charge	From $12.71 to $14.47
Trouble call charge if customer's responsibility	From $33.75 to $25.73
Reconnect charge during normal hours	From $29.40 to $33.80
Reconnect charge after normal hours	From $45.00 to $73.83

Other highlights include an increase in the minimum charge for additional meters for an individual customer from $0.97 to $18.25; and revision of the extra facilities charge in order to reflect the rate of return.

The Commission concludes that the terms and conditions of service proposed by the Company are reasonable and should be approved as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 100

The evidence supporting this finding of fact is contained in the record in this case. G.S. 62-133.2 provides that the Commission shall hold a hearing within 12 months after an electric utility's last general rate case Order to determine whether an increment or decrement rider is required "...to reflect actual changes in the cost of fuel and the fuel cost component of purchased power over or under base rates established in the last preceding general rate case." G.S. 62-133.2 further provides that additional hearings shall be held on an annual basis but only one hearing for each such utility may be held within 12 months of the last general rate case. G.S. 62-133.2(c) sets out the verified, annualized information and data which the utility is required to furnish to the Commission at the hearing for a historic 12-month period"...in such form and detail as the Commission may require..." Pursuant to Rule R8-55, the Commission has prescribed the 12-month period ending June 30, 1992, as the test period for the fuel proceeding.

The Company indicated in its July 31, 1992 Application for a General Increase in Rates (Docket No. E-22, Sub 333) that it intended to update its calculations of fuel cost in the general rate case for the 12-month period ended June 30, 1992, consistent with the Company's annual fuel clause test period. On September 30, 1992, NC Power filed a Motion for Consolidation of Hearings in which it moved to consolidate hearings in its general rate case and its fuel clause proceeding, Docket No. E-22, Subs 333 and 335, which motion was granted by the Commission in its October 5, 1992 Order. The Commission concludes that the appropriate test period for the base fuel factor determination is the 12-month period ending June 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 101-103

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witnesses Ross and Evans and Public Staff witness Lam.

Company witnesses Evans and Ross (Mr. Ross adopted the testimony of Daniel J. Green) and Public Staff witness Lam testified with regard to the July 1, 1991, to June 30, 1992, test period sales, test period generation, and normalized nuclear capacity factor. Company witnesses Ross and Evans testified that the July 1, 1991, to June 30, 1992, test period levels of sales and generation were 57,794,906 mWh and 61,448,089 mWh, respectively. The 57,794,906 mWh of test period sales reflects 57,825,522 mWh of actual sales as reported in Rule R8-55(d)(1), reduced by 30,616 mWh to reflect that Old Dominion Electric Cooperative sales are booked at production level. The test period per book system generation includes various energy generations as follows:

	mWh
Coal	25,992,366
Nuclear	22,978,300
Heavy Oil	1,912,993
Natural Gas	87,836
Internal Combustion	1,413,808
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,268,968
Other	5,234,861
Interruptible Sales	(2,551,212)

Public Staff witness Lam accepted the levels of sales and generation as proposed by the Company for use in his fuel computation.

Company witness Ross testified that the Company achieved a system nuclear capacity factor of 77.7% for the July 1, 1991, to June 30, 1992, test period. Witness Ross normalized the system nuclear capacity factor to a level of 69.24%, which is the latest North American Electric Reliability Council's (NERC) five-year nuclear capacity factor. Witness Lam agreed that the nuclear capacity factor of 77.7% as achieved by the Company was abnormally high and should be normalized to the latest NERC five-year pressurized water reactor average of 69.24%. No other party offered testimony on the normalized nuclear capacity factor. In the absence of evidence presented to the contrary, the Commission concludes that the July 1, 1991, to June 30, 1992, test period levels of sales and generation are reasonable and appropriate for use in this proceeding. The Commission further concludes that the 69.24% normalized system nuclear capacity factor is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 104

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Ross and Green and Public Staff witness Lam.

Company witness Ross and Public Staff witness Lam testified regarding normalized generation. In Docket No. E-22, Sub 333 (rate case proceeding), witness Ross proposed a normalized generation using a historical level of generation based on 12 months ended December 31, 1991. In Docket No. E-22, Sub 335 (fuel clause proceeding), witness Ross proposed a normalized generation based on the 12-month test period ended June 30, 1992. The Public Staff accepted the Company's proposed normalized generation based on the 12-month test period ended June 30, 1992, as being appropriate for use in determining the fuel factor.

The Commission concludes that normalized generation should be based on the 12-month test period ended June 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 105

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

Witness Evans testified that consistent with Commission Rule R8-55(d)(2) the Company's system sales data for the 12-month period ending June 30, 1992, was adjusted by jurisdiction for weather normalization, customer growth, and increased usage. Witness Evans adjusted total Company retail sales by 818,572 mWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 280,695 mWh, 183,088 mWh and 354,789 mWh, respectively. The Public Staff reviewed and accepted these adjustments.

Based on the foregoing evidence, the Commission concludes that the adjustments due to customer growth, increased usage, and weather normalization of 280,695 mWh, 183,088 mWh, and 354,789 mWh, respectively, are reasonable and appropriate adjustments for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 106

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Ross and Evans and Public Staff witness Lam.

Company witness Evans and Public Staff witness Lam addressed the adjusted level of generation. Witness Evans presented an adjustment to per book mWh generation for the 12-month period ended June 30, 1992, due to weather normalization, customer growth, and increased usage of 861,066 mWh, to arrive at witness Ross's adjusted generation level of 62,309,169 mWh.

The Public Staff accepted witness Evans' adjustment to per book mWh generation for the 12-month period ended June 30, 1992, due to weather normalization, customer growth, and increased usage. Witness Lam accepted witness Ross's generation level of 62,309,169 mWh which includes various energy generations as follows:

	mWh
Coal	28,130,404
Nuclear	20,474,196
Heavy Oil	2,070,346
Natural Gas	95,061
Internal Combustion	1,530,090
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,784,633
Other	5,665,469
Interruptible Sales	(2,551,212)

Based on the foregoing evidence and with no other evidence to the contrary, the Commission concludes that the adjustment of 861,066 mWh is reasonable and appropriate for use in this proceeding, and that the resultant adjusted fuel generation level of 62,309,169 mWh is also reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 107-109

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Ross and Public Staff witness Lam.

Witness Green's prefiled testimony of September 11, 1992, which was adopted by witness Ross, contained fuel prices as follows: (1) coal price of $14.27/mWh; (2) nuclear fuel price of $4.69/mWh; (3) heavy oil price of $24.90/mWh; (4) natural gas price of $30.59/mWh; (5) internal combustion turbine price of $18.50/mWh; (6) other purchased and interchanged power price of $17.23/mWh; and (7) hydro, pumped storage, and non-utility generation at a zero fuel price.

Witness Lam, in his testimony, accepted witness Ross's fuel prices for heavy oil ($24.90/mWh), natural gas ($30.59/mWh), and hydro, pumped storage, and NUG generation (zero fuel price) and total fuel cost of interruptible sales of $28,446,000. However, witness Lam updated the fuel prices for the other types of generation to September 1992 fuel prices. Heavy oil and natural gas prices were not updated because there was none or very little generation using these two fuels in September. Witness Lam recommended updated fuel prices as follows: (1) coal price of $14.26/mWh; (2) nuclear price of $4.59/mWh; (3) internal combustion turbine of $21.33/mWh; and (4) other purchased and interchanged power price of $15.12/mWh.

Witness Ross and witness Evans, on rebuttal, accepted all of the fuel prices recommended by witness Lam. In the absence of any evidence to the contrary, the Commission concludes that the Company fuel prices accepted by the Public Staff and fuel prices recommended by the Public Staff and accepted by the Company are reasonable and appropriate for use in this proceeding.

Accordingly, the fuel calculation incorporating these conclusions is shown in the following table:

	Adjusted Generation (mWh)	Fuel Price $/mWh	Fuel Dollars (000's)
Coal	28,130,404	14.26	$401,140
Nuclear	20,474,196	4.59	93,977
Heavy Oil	2,070,346	24.90	51,552
Natural Gas	95,061	30.59	2,908
Internal Combustion	1,530,090	21.33	32,637
Hydro	2,302,348		
Pumped Storage	(2,192,202)		
Purchase & Interchange			
NUG	6,784,633		
Other	5,665,469	15.12	85,662
Interruptible Sales	(2,551,212)		(28,446)
System mWh Sales & Total Fuel Cost	58,613,478		$639,430
Base Fuel Factor			1.091¢/kWh

The Commission concludes that adjusted fuel test period expenses of $639,430,000 and the base fuel factor of 1.091¢/kWh, excluding gross receipts tax (1.127¢/kWh with gross receipts tax), is reasonable and appropriate for use in this proceeding. No party opposed this calculation. This approved base fuel factor is 0.078¢/kWh lower than the current level in effect of 1.205¢/kWh, including gross receipts tax (this consists of the current base fuel factor of 1.204¢/kWh and the current fuel adjustment increment from the fuel adjustment proceeding in Docket No. E-22, Sub 329, of 0.001¢/kWh, all including gross receipts tax). Such change will result in a decrease in fuel revenues of $2,076,777 based upon the adjusted level of sales of 2,662,535 mWh for the test year through the update period ending September 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 110-112

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

North Carolina General Statute 62-133.2(d) requires the Commission to "incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period...in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case." Further, Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

Company witness Evans testified that the Company overcollected its fuel expense by $1,308,510 during the test year ending June 30, 1992. He calculated interest for this overcollection of $218,085 in accordance with Rule R8-55(c)(5) using a Commission approved 10% interest rate. Further, witness Evans testified that the adjusted North Carolina jurisdictional fuel clause test year sales are 2,629,412 mWh. Public Staff witness Lam testified that he reviewed the Company's calculations of the fuel expense overcollection, the interest for this overcollection, and the North Carolina jurisdictional sales and agreed with the results.

The Company is proposing to refund the fuel revenue overcollection and associated interest to the customers over a 12-month period beginning March 1, 1993, using the adjusted North Carolina retail sales of 2,629,412 mWh as determined by the Company and accepted by the Public Staff.

The Commission concludes that the Company's calculation of the fuel revenue overcollection and associated interest of $1,308,510 and $218,085, respectively, are appropriate for use in this proceeding and should be refunded to the customers over a 12-month period. No party opposed these calculations. This refund should be in the form of a separate EMF rider.

The $1,308,510 overcollected fuel revenue plus the $218,085 of interest was divided by the adjusted North Carolina jurisdictional sales of 2,629,412 mWh to arrive at the Company's proposed EMF decrement of 0.058¢/kWh, excluding gross receipts tax (0.060¢/kWh including gross receipts tax). Public Staff witness Lam accepted this proposed EMF decrement. The Commission concludes that there being no controversy, the proposed EMF decrement of 0.058¢/kWh, excluding gross receipts tax, is reasonable and appropriate for use in this proceeding, and shall become effective on the date of this Order and shall expire one year from that date.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 113

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

Based upon our prior findings in this proceeding the Commission finds that the final fuel factor approved for usage in this case is 1.033¢/kWh. This final fuel factor consists of a base fuel factor of 1.019¢/kWh and an EMF decrement rider, including interest, of 0.058¢/kWh, all excluding gross receipts tax.

IT IS, THEREFORE, ORDERED as follows:

1. That NC Power is authorized to adjust its electric rates and charges effective for service rendered on and after the date of this Order to produce an increase in gross annual revenue, excluding fuel revenue, from its North Carolina retail operations of $10,642,000 based upon the adjusted test year level of operations.

2. That the Company shall replace the current base fuel factor of 1.204¢/kWh, including gross receipts tax, approved in general rate case Docket No. E-22, Sub 314, with the new base fuel factor of 1.127¢/kWh, including gross receipts tax, approved in this proceeding. The Company shall also refund over-recovered fuel expense and interest in the form of a separate rider (an EMF decrement of 0.060¢/kWh including gross receipts tax). This rider shall become effective on the date of this Order and shall expire one year from that date.

3. That the Company is authorized to place in effect an increment rider of 0.066328¢/kWh to recover the remaining unamortized balance of the North Anna Unit 3 abandonment loss. This rider shall become effective on the date of this Order and shall expire one year from that date.

4. That within five (5) working days after the date of this Order, the Company shall file with the Commission five copies of its rate schedules and service regulations designed to produce the increase in revenues adopted herein in accordance with the rate design guidelines attached hereto as Appendix A. The rate schedules required herein shall be accompanied by computations showing the level of revenues which will be produced by the rates for each rate schedule.

5. That the Company shall prepare cost allocation studies for presentation with its next general rate case which allocate production plant based on the following methodologies: (a) Summer/Winter Peak and Average; (b) Summer/Winter Coincident Peak; (c) Average and Excess. The studies shall be included in Item 45 of Form E-1 of the minimum filing requirements for general rate applications.

6. That within 10 working days after the date of this Order, the Company shall file with the Commission 30 copies of computations showing the overall North Carolina retail rate of return and the rates of return for each rate schedule which will be produced by the revenues approved by this Order. These computations shall be based on the cost allocation methodology approved by this Order.

7. That the Company shall give appropriate notice of the approved rate increase by mailing a notice to each of its North Carolina retail customers during the next normal billing cycle following the filing and approval of the rate schedules described herein. The Company shall submit its proposed customer notice to the Commission for approval before it is mailed to the customers.

8. That the Company shall file new revised standards necessary to qualify for the Residential Conservation Reduction (RCR), which shall show that the relative benefit of the new revised standards to the new building code is substantially the same as the relative benefit of the current standards to the current building code as described herein. The new revised standards shall be filed with the Commission by April 15, 1993.

9. That the proposed new Line Extension Plan as described herein is hereby approved to become effective 90 days after the date of this Order.

10. That the Company shall make a study of the fuel costs and other costs incurred to serve the LGS customer class relative to the remainder of the system in accordance with the Commission's conclusions described herein. The results of the study and supporting workpapers shall be filed with the Commission and the

Public Staff within 12 months after the date of this Order. The Company shall also file quarterly reports with the Commission regarding the progress of the studies as described herein.

11. That the company shall file a report with the Commission approximately 12 months after the date of this Order describing the number of customers added and lost from the curtailable rate schedules 6C, SG and CS since the date of this Order.

12. That the Company's proposed change to paragraph II. A.1 of its Terms and Conditions for the delivery of electric service rules and regulations is disapproved.

13. That the other proposed rate designs and modification and the other purposed changes in the Terms and Conditions are approved and may be implemented.

14. That the Public Staff shall investigate Vepco's NUG contracts for projects in commercial operation in conjunction with NC Power's next general rate case and present the results of such investigation as part of its testimony in that proceeding.

ISSUED BY ORDER OF THE COMMISSION
This the 26th day of February, 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Commissioner Cobb dissenting in part.

APPENDIX A

NORTH CAROLINA POWER
DOCKET NO. E-22, SUB 333
Guidelines for Design of Rate Schedules

(A) Set the Basic Customer Charge for Residential Service at $9.50.

(B) Hold the extra charges and miscellaneous service charges at the same levels proposed by the Company.

(C) Distribute the overall revenue increase approved herein in accordance with the following rate of increase indices:

	Rate of Increase Index
Residential	1.125
Small General Service	1.000
Large General Service	0.875
Outdoor Lighting	1.000
Traffic Signals	1.000
Overall	1.000

(D) Maintain revenue neutrality between comparable time-of-use rate schedules and non-time-of-use rate schedules.

(E) Maintain the relative price levels proposed for each rate schedule consistent with the overall rates of increase approved herein, except as specifically revised herein.

COMMISSIONER COBB, DISSENTING, IN PART.

1. I dissent from Finding of Fact 59 which reduces the operation and maintenance expense by $1,390,000 to reflect alleged unreasonable purchase capacity costs in connection with the Hadson projects. While I agree that this Commission is not bound by the actions of the Virginia State Corporation Commission as a matter of law, I do not feel that the factual situation in this case justifies such disallowance. Neither do I agree with the majority concerning the standards to be met for disallowance.

   The majority cites other cases involving the adjustment of fuel expenses to reflect abnormal weather conditions and other factors as justification for its conclusion that there need not be a finding of management imprudence to disallow expenses. These decisions are readily distinguishable in that failure to adjust clearly would have resulted in the substantial over recovery of expenses whereas the majority decision in this case will preclude the recovery of $1,390,000 in costs actually incurred.

   In my opinion, North Carolina Power did everything a reasonable and prudent person would be expected to do but became subject to pay these purchased power costs because of the decision of an authority having jurisdiction of the subject matter. I would hold that to disallow the recovery of costs actually incurred, we would need to find a lack of reasonable and prudent action on the part of North Carolina Power.

2. I also dissent from those parts of Findings of Fact 60, 61 and 62 to the extent that they conflict with Commission Rules R12-12 and R12-13. Once again the majority has solved a difficult problem by "splitting the difference" and disallowing half of the alleged competitive advertising because some of the ads made reference to natural gas. While compromise verdicts may be excused where reached by juries, it is my understanding that our findings of fact must be based upon evidence in the record. They also must be in conformance with our rules.

   As I read Rules R12-12(d) and R12-13(c), advertising which comes within any of the six subparagraphs of R12-12(d) will be deemed reasonable operating expenses except to the extent that the expenditures might have exceeded a reasonable amount. There is no reference in either of these rules to competitive advertising. In my opinion, the thrust of the entire co-op advertising company was to promote energy efficiency so that the entire expense would be reasonable under Rule R12-12(d)(1) and (5). If we are going to disallow such advertising because of the Public Staff's contention that ads should not promote the use of electricity over gas, we should amend our rules to specifically disallow such advertising.

   The disallowance of the "promotional advertising" by the majority clearly is inconsistent with the definition of such advertising in Rule R12-12(c). The rule defines such advertising as that which encourages the use of electricity where "...such appliance, equipment, or service would promote or encourage indiscriminate and wasteful consumption of energy...."

Furthermore, such advertising must have a disclaimer to the extent that the advertising is not paid for by the customers of the utility. I would have found this advertising to be recoverable either under Rule R12-12(d) or Rule R12-13(d).

I also have difficulty with the disallowance of the "image advertising" because recovery for such expenses is not precluded by our rules. If such a policy is to be continued, the rules should be amended. Until this is done, I am of the opinion that these expenses should have been recovered under Rules R12-12(d) and R12-13(d).

3. Finally, I dissent from Finding of Fact 63 which disallows half of the compensation of officers. My opinion in this regard is set forth in my dissent in Docket No. E-22, Sub 314 and need not be repeated here. Suffice to say I continue to believe that such disallowance is arbitrary and capricious and beyond the authority granted by law.

Laurence A. Cobb

DOCKET NO. E-22, SUB 344

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of North Carolina Power	)	
Pursuant to G.S. § 62-133.2 and	)	ORDER APPROVING
NCUC Rule R8-55 Relating to Fuel Charge	)	NET FUEL CHARGE
Adjustments for Electric Utilities	)	RATE DECREASE

HEARD: Wednesday, November 10, 1993, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Allyson K. Duncan, Presiding; Commissioners Charles H. Hughes and Ralph A. Hunt

APPEARANCES:

For North Carolina Power:

James S. Copenhaver, Senior Regulatory Counsel, North Carolina Power, Post Office Box 26666, Richmond, Virginia 23261

For the Public Staff:

Paul L. Lassiter, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

For Carolina Industrial Group for Fair Utility Rates (CIGFUR-I)

Ralph McDonald, Bailey and Dixon, Attorneys at Law, Post Office Box 12865, Raleigh, North Carolina 27605-2865

BY THE COMMISSION: G.S. § 62-133.2 requires the Commission to hold a hearing for each electric utility engaged in the generation and production of electric power by fossil or nuclear fuel within 12 months after the last general rate case order for each utility for the purpose of determining whether an increment or decrement rider is required to reflect actual changes in the cost of fuel and the fuel component of purchased power over or under the base fuel component established in the last general rate case. The statute further requires that additional hearings be held on an annual basis, but only one hearing for each utility may be held within 12 months of it's last general rate case. In addition to the increment or decrement rider to reflect changes in the cost of fuel and the fuel component of purchased power, the Commission is required to incorporate in its fuel cost determination the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test year. The last general rate case order for North Carolina Power (or "the Company") was issued by the Commission on February 26, 1993, in Docket No. E-22, Sub 333. The last order approving a fuel charge adjustment for the Company was issued on February 26, 1993, in Docket No. E-22, Sub 335. The aforementioned fuel charge adjustment and general rate cases were consolidated for hearing.

North Carolina Power filed a fuel adjustment application and supporting testimony and exhibits in accordance with Rule R8-55 and G.S. § 62-133.2 on September 10, 1993. North Carolina Power filed testimony and exhibits for the following witnesses: Thomas H. Christian - Director, Corporate Accounting; Thomas Q. Taylor - Staff Power Analyst; and Glenn A. Pierce - Regulatory Specialist, Rate Design. The Company also filed information and workpapers required by NCUC Rule R8-55(d).

On September 16, 1993, the Commission issued an Order Scheduling Hearing and Requiring Public Notice of this proceeding.

The Carolina Industrial Group for Fair Utility Rates (CIGFUR) filed a Petition to Intervene on September 28, 1993, which petition was granted by Order dated September 30, 1993. The Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene on October 7, 1993, which petition was granted by Order dated October 11, 1993.

On October 13, 1993, the Company filed a Notice of Affidavits, which indicated that the Company would enter its testimony into the record by affidavit at the hearing in the absence of an objection from any party. No such objection was raised by any party. On October 25, 1993, the Public Staff filed an affidavit of Thomas S. Lam that recommended approval of the Company's fuel adjustment filing subject to certain specified modifications and corrections.

On November 1, 1993, the Company filed an affidavit of Glenn A. Pierce, which adopted the corrections and modifications proposed by Public Staff witness Lam.

The matter came on for hearing as scheduled on Wednesday, November 10, 1993. The prefiled testimony of the Company's witnesses was stipulated into the record by affidavit. The affidavit of Public Staff witness Lam (as corrected on November 9, 1993), the supplemental affidavit of Company witness Pierce and the exhibits of all of the witnesses were admitted into evidence.

Based upon the foregoing, the prefiled testimony and affidavits of Company witnesses Christian, Taylor and Pierce and Public Staff witness Lam, and the entire record, the Commission makes the following:

FINDINGS OF FACT

1. North Carolina Power is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. The Company has its principal offices and place of business in Richmond, Virginia.

2. The test period for purposes of this proceeding is the 12 months ended June 30, 1993.

3. The Company's fuel procurement and power purchasing practices during the test period were reasonable and prudent.

4. The test period per book system sales are 60,309,476 mWh after adjusting for Old Dominion Electric Cooperative (ODEC) sales which are booked at production level.

5. The test period per book system generation is 63,975,273 mWh which includes various energy generations as follows:

	mWh
Coal	25,889,169
Combustion Turbine	1,708,273
Heavy Oil	821,684
Natural Gas	404
Nuclear	23,892,151
Hydro	2,931,558
Pumped Storage	(2,511,175)
Power Transactions	
NUG	7,810,092
Other	4,814,903
Sales for Resale	(1,381,791)

6. The normalized system nuclear capacity factor which is appropriate for use in this proceeding is 71.56%.

7. The adjusted test period sales of 61,755,417 mWh results from an additional 310,971 mWh of customer growth, 462,139 mWh of additional customer usage, an additional 672,831 mWh associated with weather normalization, and a

decrease of 49,951 mWh from the restatement of non-jurisdictional ODEC sales from production level to sales level, added to test period system sales of 60,359,427 mWh.

8. The adjusted test period system generation for use in this proceeding is 65,497,092 mWh which includes various energy generations as follows:

	mWh
Coal	28,714,756
Combustion Turbine	1,894,717
Heavy Oil	911,349
Natural Gas	455
Nuclear	20,934,305
Hydro	2,931,558
Pumped Storage	(2,511,175)
Power Transactions	
NUG	8,662,482
Other	5,340,399
Interruptible Sales	(1,381,791)

9. The appropriate fuel prices for use in this proceeding are as follows:

A. The coal fuel price is $14.18/mWh.
B. The nuclear fuel price is $4.36/mWh.
C. The heavy oil fuel price is $25.05/mWh.
D. The natural gas price is $30.59/mWh.
E. The internal combustion turbine (IC) fuel price is $26.24/mWh.
F. The fuel price for other power transactions is $18.21/mWh.
G. Hydro, pumped storage, and non-utility generation (NUG) have a zero fuel price.

10. The adjusted system fuel expense for the July 1, 1992, to June 30, 1993 test period for use in this proceeding is $627,501,916.

11. The appropriate fuel factor for this proceeding is 1.016¢/kWh, excluding gross receipts tax.

12. The Company's North Carolina test period jurisdictional fuel expense overcollection is $3,323,327. The adjusted North Carolina jurisdictional test year sales are 2,808,528 mWh.

13. Interest expense associated with the overcollection of test period fuel revenues amounts to $498,499, based upon a 10% annual interest rate.

14. The Company's Experience Modification Factor (EMF) and interest combine for a decrement of 0.136¢/kWh, excluding gross receipts tax.

15. The final fuel factor is 0.880¢/kWh, excluding gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. § 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. In Rule R8-55(b), the Commission has prescribed the 12 months ending June 30 as the test period for North Carolina Power. The Company's filing on September 10, 1993, was based on the 12 months ended June 30, 1993.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Rule R8-52(b) requires each utility to file a Fuel Procurement Practices Report at least once every ten years, plus each time the utility's fuel procurement practices change. Procedures related to North Carolina Power's procurement of fossil and nuclear fuels were filed in Docket No. E-22, Sub 335, on April 2, 1993. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a).

No party offered direct testimony contesting the Company's fuel procurement and power purchasing practices. In the absence of any direct testimony to the contrary, the Commission concludes these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witnesses Taylor and Pierce and Public Staff witness Lam.

Company witnesses Taylor and Pierce and Public Staff witness Lam testified with regard to the July 1, 1992 to June 30, 1993 test period sales, test period generation, and normalized nuclear capacity factor. Company witnesses Taylor and Pierce testified that the test period levels of sales and generation were 60,309,476 mWh and 63,975,273 mWh, respectively. The 60,309,476 mWh of test period sales reflects 60,359,427 mWh of actual sales as reported in Rule R8-55(d)(1), reduced by 49,951 mWh to reflect that ODEC sales are booked at production level. The test period per book system generation includes various energy generations as follows:

	mWh
Coal	25,889,169
Combustion Turbine	1,708,273
Heavy Oil	821,684
Natural Gas	404
Nuclear	23,892,151
Hydro	2,931,558
Pumped Storage	(2,511,175)
Power Transactions	
NUG	7,810,092
Other	4,814,903
Sales for Resale	(1,381,791)

Public Staff witness Lam accepted the levels of sales and generation as proposed by the Company for use in his fuel computation.

Company witness Taylor testified that the Company achieved a system nuclear capacity factor of 81.9% for the July 1, 1992 to June 30, 1993 test period. Witness Taylor normalized the system nuclear capacity factor to a level of 71.56%, which is the latest North American Electric Reliability Council's (NERC) average nuclear capacity factor. Witness Lam agreed that the nuclear capacity factor of 81.9% as achieved by the Company should be normalized to the latest NERC five-year pressurized water reactor average nuclear capacity factor of 71.56%. No other party offered testimony on the normalized nuclear capacity factor. In the absence of evidence presented to the contrary, the Commission concludes that the July 1, 1992 to June 30, 1993 test period levels of sales and generation are reasonable and appropriate for use in this proceeding. The Commission further concludes that the 71.56% normalized system nuclear capacity factor is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Pierce and Public Staff witness Lam.

Witness Pierce testified that, consistent with Commission Rule R8-55(d)(2), the Company's system sales data for the 12-month period ending June 30, 1993 was adjusted by jurisdiction for weather normalization, customer growth, and increased usage. Witness Pierce adjusted total Company sales by 1,445,941 mWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 310,971 mWh, 462,139 mWh and 672,831 mWh, respectively. The Public Staff reviewed and accepted these adjustments.

Based on the foregoing evidence, the Commission concludes that the adjustments due to customer growth, increased usage, and weather normalization of 310,971 mWh, 462,139 mWh, and 672,831 mWh, respectively, are reasonable and appropriate adjustments for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Taylor and Pierce and Public Staff witness Lam.

Company witness Pierce and Public Staff witness Lam addressed the adjusted level of generation. Witness Pierce presented an adjustment to per book mWh generation for the 12-month period ended June 30, 1993, due to weather normalization, customer growth, and increased usage of 1,521,833 mWh, to arrive at witness Taylor's adjusted generation level of 65,497,092 mWh.

Witness Lam accepted witness Pierce's adjustment to per book mWh generation for the 12-month period ended June 30, 1993, due to weather normalization, customer growth, and increased usage. Witness Lam also accepted witness Taylor's generation level of 65,497,092 mWh which includes various energy generations as follows:

	mWh
Coal	28,714,756
Combustion Turbine	1,894,717
Heavy Oil	911,349
Natural Gas	455
Nuclear	20,934,305
Hydro	2,931,558
Pumped Storage	(2,511,175)
Power Transactions	
NUG	8,662,482
Other	5,340,399
Interruptible Sales	(1,381,791)

Based on the foregoing evidence and with no other evidence to the contrary, the Commission concludes that the adjustment of 1,521,833 mWh is reasonable and appropriate for use in this proceeding, and that the resultant adjusted fuel generation level of 65,497,092 mWh is also reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Taylor and Public Staff witness Lam.

Witness Taylor testified that the Company's proposed fuel factor is based on June 1993 fuel prices as follows: (1) coal price of $14.23/mWh; (2) nuclear fuel price of $4.36/mWh; (3) heavy oil price of $25.98/mWh; (4) natural gas price of $30.59/mWh; (5) internal combustion turbine price of $26.24/mWh; (6) other power transactions price of $18.21/mWh; and (7) hydro, pumped storage, and non-utility generation at a zero fuel price.

Witness Lam, in his testimony, accepted witness Taylor's fuel prices for nuclear fuel ($4.36/mWh), natural gas ($30.59/mWh), internal combustion turbine ($26.24/mWh), other power transactions ($18.21/mWh), and hydro, pumped storage, and NUG generation (zero fuel price). However, witness Lam updated the fuel prices for the other types of generation to August 1993 fuel prices. Witness Lam recommended updated fuel prices as follows: (1) coal price of $14.18/mWh; and (2) heavy oil price of $25.05/mWh.

Witness Pierce filed a supplemental affidavit, accepting the revised fuel prices recommended by witness Lam. In the absence of any evidence to the contrary, the Commission concludes that the Company fuel prices accepted by the

Public Staff and fuel prices recommended by the Public Staff and accepted by the Company are reasonable and appropriate for use in this proceeding.

The Commission concludes that adjusted fuel test period expenses of $627,501,916 and the fuel factor of 1.016¢/kWh, excluding gross receipts tax (1.050¢/kWh with gross receipts tax), is reasonable and appropriate for use in this proceeding. No party opposed this calculation. This approved base fuel factor is 0.077¢/kWh lower than the current base fuel factor in effect of 1.127¢/kWh, including gross receipts tax. Such change will result in a decrease in fuel revenues of $2,162,567 based upon the adjusted level of sales of 2,808,528 mWh for the test year.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Pierce and Public Staff witness Lam.

G.S. 62-133.2(d) requires the Commission to "incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case." Further, Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

Company witness Pierce testified that the Company overcollected its fuel expense by $3,232,324 during the test year ending June 30, 1993. He calculated interest for this overcollection of $484,849 in accordance with Rule R8-55(c)(5) using a Commission approved 10% interest rate. Further, witness Pierce testified that the adjusted North Carolina jurisdictional fuel clause test year sales are 2,808,528 mWh.

Public Staff witness Lam testified that he reviewed the Company's calculations of the fuel expense overcollection, the interest for this overcollection, and the North Carolina jurisdictional sales and agreed with the results, subject to two adjustments. The first adjustment of $67,684 is to correct a Company error in prorating the kWh sales. The second adjustment of $23,319 to the EMF calculation deals with NUG fuel costs included in purchased power fuel costs. In its filing, the Company failed to exclude fuel expenses pertaining to certain NUGs for amounts incurred from February 26 through February 28, 1993. The total expenses related to these NUG projects were included in the non-fuel base rates beginning February 26, 1993. The interest differential associated with these adjustments is $13,650. Witness Lam's Exhibit TSL-2 is a schedule of the computation of the EMF based on these adjustments. Company witness Pierce accepted these corrections in his supplemental affidavit.

The Company is proposing to refund the fuel revenue overcollection and associated interest to the customers over a 12-month period beginning January 1, 1994, using the adjusted North Carolina retail sales of 2,808,528 mWh as determined by the Company and accepted by the Public Staff.

The Commission concludes that the Company's calculation of the fuel revenue overcollection and associated interest as adjusted by witness Lam of $3,323,327 and $498,499, respectively, are appropriate for use in this proceeding and should be refunded to the customers over a 12-month period. No party opposed these calculations. This refund should be in the form of a separate EMF rider - Rider B1 (Rider B is the EMF rider instituted in Docket No. E-22, Sub 335 and will not expire until February 26, 1994).

The $3,323,327 overcollected fuel revenue plus the $498,499 of interest was divided by the adjusted North Carolina jurisdictional sales of 2,808,528 mWh to arrive at an EMF decrement of 0.136¢/kWh, excluding gross receipts tax (0.141¢/kWh including gross receipts tax). The Company and the Public Staff were in agreement regarding the proper EMF decrement. The Commission concludes that there being no controversy, the proposed EMF decrement of 0.136¢/kWh, excluding gross receipts tax, is reasonable and appropriate for use in this proceeding, and shall become effective on January 1, 1994 and shall expire one year from that date.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Pierce and Taylor and Public Staff witness Lam.

Based upon our prior findings in this proceeding the Commission finds that the final net fuel factor approved for usage in this case is 0.880¢/kWh. This final fuel factor consists of a base fuel factor of 1.091¢/kWh, a primary fuel cost factor decrement (Rider A) of 0.075¢/kWh, and an EMF decrement rider (Rider B1), including interest, of 0.136¢/kWh. With the current EMF decrement rider (Rider B) of 0.058¢/kWh the fuel factor effective January 1, 1994 through February 26, 1994 will be 0.822¢/kWh excluding gross receipts tax.

The fuel calculation incorporating these conclusions is shown in the following table:

	Adjusted Generation (MWh)	Fuel Price $/MWh	Fuel Dollars (000's)
Coal	28,714,756	14.18	407,175
Nuclear	20,934,305	4.36	91,274
Heavy Oil	911,349	25.05	22,829
Natural Gas	455	30.59	14
Combustion Turbine	1,894,717	26.24	49,717
Hydro	2,931,558		
Pumped Storage	(2,511,175)		
Power Transactions			
NUG	8,662,462		
Other	5,340,399	18.21	97,249
Sales for Resale	(1,381,791)		(40,756)
System MWh Sales & Total Fuel Cost	61,755,417		627,502

	Effective 1/1/94	Effective 2/26/94
	(Including Gross Receipts Tax)	
Base Fuel Factor ¢/kWh	1.127	1.127
EMF/Rider B ¢/kWh	(0.060)	
EMF/Rider B1 ¢/kWh	(0.141)	(0.141)
Fuel Cost/Rider A ¢/kWh	(0.077)	(0.077)
Final Fuel Factor ¢/kWh	0.849	0.909

IT IS, THEREFORE, ORDERED, as follows:

1. That effective beginning with usage on and after January 1, 1994, North Carolina Power shall adjust the base fuel component in its North Carolina retail rates approved in Docket No. E-22, Sub 335, by a decrement (Rider A) of 0.075¢/kWh (excluding gross receipts tax).

2. That an EMF Rider decrement (Rider B1) of 0.136¢/kWh (excluding gross receipts tax) shall be instituted and remain in effect for usage from January 1, 1994, until December 31, 1994.

3. That North Carolina Power shall notify its North Carolina retail customers of the rate adjustments approved in this proceeding by including the "Notice to Customers of Rate Reduction" attached to this Order as Appendix A as a bill insert with customer bills rendered during the next regularly scheduled billing cycle.

4. That North Carolina Power shall file appropriate rate schedules and riders with the Commission in order to implement these approved fuel charge adjustments no later than 10 days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of December 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 344

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of North Carolina Power Pursuant to G.S. § 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities) NOTICE TO CUSTOMERS OF RATE REDUCTION

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order in this docket on December 21, 1993, after public hearings, approving a $4.5 million reduction in the annual rates and charges paid by the retail customers of North Carolina Power in North Carolina. The rate reduction will be effective beginning with the next regularly scheduled monthly billing cycle. The rate reduction was ordered by the Commission after a review of North Carolina Power's fuel expenses during the 12-month test period ended June 30, 1993, and represents actual changes experienced by the Company with respect to its reasonable costs of fuel and the fuel component of purchased power during the test period.

For a typical residential customer using 1,000 kWh per month, the Commission's Order will result in a net rate reduction of approximately $1.60 per month from the previous effective rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of December, 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. E-2, SUB 642

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Carolina Power & Light Company's Petition for Authority to Issue a Promissory Note to Purchase Sulfur Dioxide Emission Allowances	))))	PROTECTIVE ORDER

BY THE COMMISSION: On April 1, 1993, Carolina Power & Light Company (CP&L or Company) filed a petition pursuant to G.S. 62-167 requesting authority to issue a seven-year promissory note to purchase 150,000 sulfur dioxide emission allowances. On that same date, CP&L also filed a motion whereby the Commission was requested to enter a Protective Order prohibiting the public disclosure to anyone other than members of the Commission, its staff, and/or the Public Staff of the purchase price and the vendor of the sulfur dioxide emission allowances in question. In support of its motion for Protective Order, CP&L asserts that the sulfur dioxide emission allowance market is very competitive. According to CP&L, if the market was made aware of the purchase price or the vendor of these allowances, the ability of both CP&L and the seller to compete in this market would be greatly impaired. Other potential buyers would know the price at which the seller is willing to sell allowances. Similarly, other potential sellers would know the price at which CP&L is willing to purchase allowances.

On April 7, 1993, CP&L filed a supplement to its motion for Protective Order asserting that the identity of the seller of the emission allowances in question and the purchase price of those emission allowances constitute a trade secret under G.S. 132-1.2 and G.S. 66-152(3) and should be protected from public disclosure. CP&L assets that it has negotiated a price for the allowances in question that is very attractive for its shareholders and ratepayers and that the Company's contract for additional emission allowances in the future at the lowest possible cost will be jeopardized if the identity of the seller and/or the purchase price of the subject allowances is publicly disclosed. According to CP&L, all electric utilities are actively searching for emission allowances at the lowest possible cost. This information must remain secret in order for CP&L to maintain its competitive position with respect to future purchases of emission allowances at favorable prices. CP&L further states that if this information were publicly disclosed, other vendors of emission allowances would know the price at which CP&L is willing to purchase such allowances; and other electric utilities would discover that the seller has allowances for sale, would know the price at which the seller is willing to sell its sulfur dioxide emission allowances, and would attempt to purchase them. CP&L also amended its petition to indicate that the confidential information in question could also be disclosed to representatives of the Attorney General's office assigned to investigate the matter.

On the basis of the foregoing, the Commission finds good cause to enter this Protective Order as requested by CP&L.

IT IS, THEREFORE, ORDERED that public disclosure of the purchase price and vendor of the sulfur dioxide emission allowances which are the subject of this docket be, and the same is hereby, prohibited pursuant to the provisions of this Protective Order; provided, however, that members of the Commission and employees of the Commission Staff, Public Staff, and Attorney General's office assigned to evaluate the petition in question shall have access to the information designated as a trade secret and confidential by CP&L.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of April 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. SP-77
DOCKET NO. SP-100, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. SP-77

In the Matter of
Application for a Certificate of Public Convenience and Necessity Pursuant to G.S. 62-110.1(a) for Construction of a Cogeneration Facility to be Located Adjacent to Becker Farms Industrial Park Between Roanoke Rapids and Weldon, North Carolina

Docket No. SP-100, Sub 2

In the Matter of
Request for a Declaratory Ruling by Westmoreland-LG&E Partners

ORDER ON NOTICE OF AMENDED INFORMATION AND ON REQUEST FOR DECLARATORY RULING

BY THE COMMISSION: On July 22, 1993, Westmoreland-LG&E Partners (WLP) filed its Notice of Amended Information Pursuant to Rule R1-37(d)(3) (Notice) in Docket No. SP-77. This Notice reflects changes that have occurred to WLP's Roanoke Valley I Project (ROVA I) since the Commission issued it a certificate of public convenience and necessity under G.S. 62-110.1 on September 27, 1990. This Notice includes new information concerning the proposed termination of ROVA I's qualifying facility (QF) status under the Public Utility Regulatory Policies Act of 1978 (PURPA) and its conversion to eligible facility (EF) status under the Energy Policy Act of 1992 (EPACT). WLP asks the Commission to declare that the new information does not affect the validity of the existing certificate.

On September 10, 1993, WLP filed a Request for a Declaratory Ruling (Request) and brief in Docket No. SP-100, Sub 2, asking the Commission to issue a declaratory ruling that its proposed activities would not render it a public utility under North Carolina law or, alternatively, to permit deviation from Commission rules and declare WLP exempt from North Carolina public utility regulation. The Public Staff filed its Response to WLP's Request for a Declaratory Ruling on October 1, 1993.

A Stipulation between the Public Staff and WLP was filed on October 1, 1993.

under PURPA and currently exempt, pursuant to 16 U.S.C. 824a-3(e) and 18 C.F.R. 292.601 and 292.602, from both federal and state public utility regulation. ROVA II is not affected by either the Notice or Request. ROVA I is a 165-megawatt facility under construction near Roanoke Rapids and Weldon, North Carolina, approximately 1/4 of a mile from N.C. Highway 158 in Halifax County. The electricity generated by ROVA I will be sold to Virginia Electric & Power Company (Virginia Power) under a Power Purchase Agreement that originally was awarded to Beckley Cogeneration Company as a result of Virginia Power's 1988 competitive bidding process and executed on January 24, 1989. This contract was subsequently assigned to WLP and amended twice to reflect changes in ownership, rates, site and fuel supply. This contract allows the QF status of ROVA I to be terminated. WLP currently has a contract with Patch Rubber Company (Patch), an industry located in the adjacent Becker Farms Industrial Park, that requires Patch to buy enough process steam for ROVA I to qualify as a QF. Patch intends to use the steam for process heating and cooling and also for space heating and air conditioning.

On June 28, 1993, WLP applied to the Federal Energy Regulatory Commission (FERC) for status as an exempt wholesale generator (EWG) pursuant to the EPACT and for a determination that the rates contained in its contract with Virginia Power for ROVA I are just and reasonable. WLP's application for EWG status was published in the Federal Register, as required by the FERC's rules, and subsequently was granted on August 16, 1993. Its rate approval request is still pending. Section 711 of the EPACT defines an EWG as a person determined to be engaged directly (or indirectly through one or more affiliates) and exclusively in the business of owning and/or operating all or part of one or more eligible facilities and selling electric energy at wholesale. An eligible facility (EF) is defined as a facility that is used for the generation of electric energy exclusively for sale at wholesale or used for generation and leased to a public utility company (and treated as a wholesale sale).

WLP states in its Notice that it intends to terminate ROVA I's QF status as of its commercial operation date, if all lender and regulatory approvals are obtained, and operate the facility solely as an EF. Upon terminating the facility's QF status, WLP could amend its contract with Patch, since there would be no minimum QF steam supply requirement, and sell steam to Patch and possibly up to four other industries located, or to be located, in the adjacent industrial park. WLP cites the potential to improve its overall project economics, reduce its long-term business risk, and enhance its ability to assist in local development efforts as the reasons for its intended termination of QF status.

WLP states in its Request that it plans to sell its electricity to Virginia Power pursuant to its existing Power Purchase Agreement. The Agreement allows WLP to terminate ROVA I's QF status and become an EF at its option. WLP is contemplating selling steam to no more than five industries located in the adjacent industrial park upon termination of QF status. WLP contends that, under these circumstances, it would be neither an electric nor a steam public utility under North Carolina law, and its asks the Commission to issue a declaratory ruling to that effect. Alternatively, if the Commission rules that WLP would become a public utility by terminating its QF status and undertaking the activities described, WLP asks the Commission to permit deviation from its rules and exempt it from regulation.

The two filings will be discussed separately.

REQUEST FOR DECLARATORY RULING

WLP's Request seeks a ruling as to whether its proposed activities would render it a public utility. The Request presents two issues: (1) whether WLP would be a public utility by virtue of its terminating QF status and its sale of electricity to Virginia Power and (2) whether WLP would be a public utility by virtue of its terminating QF status and its sale of steam to one or more industries located or to be located in an adjacent industrial park.

With respect to its sale of electricity, WLP argues that it would not be an electric public utility because the Commission's reasoning in Request for a Declaratory Ruling by Cogentrix of North Carolina, Inc., Docket No. SP-100 (1984)(Cogentrix) applies analogously to ROVA I as a non-QF facility owned by an EWG. WLP also argues that the Commission's Order in Application of Empire Power Company, Docket No. SP-91 (1992) (Empire) supports its position because the Commission distinguished between independent power producers and public utilities in that Order. Further, WLP discusses the Supreme Court's decision in State ex rel. Utilities Commission v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978) (Simpson) and concludes that WLP is not a public utility. Alternatively, WLP requests that if the Commission finds it to be a public utility, the Commission permit deviation from the Commission's rules and declare WLP exempt from all relevant statutes and rules.

The Public Staff, in its Response, asserts that the Commission's Cogentrix and Empire Orders are inapplicable. The Public Staff concludes that it is necessary to analyze WLP's proposed production and sale of electricity under the standard enunciated in Simpson. Thus, whether the proposed sale of electricity by WLP as an EWG from a non-QF to Virginia Power is a sale "to or for the public" depends upon the regulatory circumstances of this case. The Public Staff discusses the factors in favor of finding WLP to be a public utility and those against such a finding. The Public Staff concludes that WLP should be exempt from all non-statutory requirements, but be required to file certain reports and provide access to its books and records. Alternatively, the Public Staff requests that if the Commission finds WLP not to be a public utility, it condition its certificate on the access and reporting requirements under its plenary authority pursuant to G.S. 62-110.1.

G.S. 62-3(23)(a)(1), in relevant part, defines "public utility" as any person owning or operating, in North Carolina, equipment or facilities for producing, generating, transmitting, delivering or furnishing electricity to or for the public for compensation. G.S. 62-3(23)(b) provides that the term "public utility" shall for ratemaking purposes include any person producing, generating or furnishing any of the services listed in subsection (a) to another person for distribution to or for the public for compensation. There is no question that WLP owns and will be operating, in North Carolina, equipment or facilities for producing, generating, transmitting, delivering or furnishing electricity for compensation. The question is whether or not WLP's sale of electricity is "to or for the public."

The standard for determining whether any given enterprise is a public utility within the meaning of the regulatory scheme in Chapter 62 was established by the Supreme Court in the Simpson case. The Court admonished against an abstract, formalistic definition of "public" to be thereafter universally applied and granted the Commission considerable flexibility in determining the meaning of "to or for the public." The Court held that what constitutes the "public" in a given case depends on the regulatory circumstances of that case. 295 N.C. at 519. The Simpson Court identified some of these circumstances as (1) the nature of the industry sought to be regulated, (2) the type of market served by the industry, (3) the kind of competition that naturally inheres in that market, and (4) the effect of non-regulation or exemption from regulation of one or more persons engaged in the industry. In the final analysis, the meaning of the "public" must be such as will accomplish the "legislature's purpose and comport with its public policy." Id.

G.S. 62-2 declares it to be the policy of the State to promote the inherent advantages of regulated public utilities, to promote adequate, reliable and economic utility service, and to foster continued service of public utilities on a well-planned and coordinated basis, among other things. It is well-established that the public policy basis of the requirement for a certificate of public convenience and necessity is the General Assembly's adoption of the policy that nothing else appearing, the public is better served by a regulated monopoly than by competing suppliers of the same service. State ex rel. Utilities Commission v. Carolina Telephone & Telegraph Company, 267 N.C. 257, 148 S.E.2d 100 (1966)(Carolina Telephone). The Supreme Court has held that one offers service to the "public" when he holds himself out as willing to serve up to the capacity of his facilities without regard to the facts that his service is limited to a specified area and his facilities are limited in capacity. Carolina Telephone, 267 N.C. at 268.

The EPACT introduced wholesale competition into an industry traditionally dominated by monopoly providers. Because of this, factors that have not previously been involved in this type of proceeding must be considered. The Commission should maintain flexibility to adjust to changes in the industry while not imposing unnecessary burdens on WLP.

The factors that mitigate against WLP being regulated as a public utility include the following: (1) WLP will sell only to Virginia Power and is prohibited from selling electricity to anyone else by both its contract and its certificate, (2) WLP is not affiliated with Virginia Power, (3) the contract between them resulted from the assignment of a contract resulting from a competitive bidding process and arms length bargaining, (4) the Commission has the authority to regulate Virginia Power's rates and control its selection of generating options through the ratemaking process, and (5) regulating WLP because of its sale of electricity at wholesale will not aid the development of wholesale competition, which is one of the goals of the EPACT.

Given the facts as set forth in WLP's Request and Notice, the conditions and requirements discussed herein, and current law, the Commission concludes that WLP should not be considered a public utility under G.S. 62-110.1(a) by virtue of its sale of electricity to Virginia Power. Subsection (b) appears to cover this type of sale, but it would render WLP a public utility "for ratemaking purposes" only. The Commission is pre-empted from setting the rates of an EWG by federal law.

Because of the important policy considerations inherent in this matter, the right of access to WLP's books and records and certain reporting requirements will be made conditions of WLP's certificate. This will be discussed in detail in the next section of this Order.

It must be emphasized that the Commission's decision turns upon the specific facts of this case and is conditioned upon the representations in WLP's Notice, Request, the Stipulation and current law. No precedent is being established that will be applied automatically to an application by an EWG or any other person in the future. The Commission does not hereby announce any policy or intentions with respect to any such future applications and will deal with each application and specific fact situation as it is presented.

We now turn to the question of whether termination of ROVA I's QF status and sale of steam to up to five industries in an adjacent industrial park renders WLP, as the owner of ROVA I, a public utility.

WLP argues that the proposed sale of steam to as many as five industries located or to be located in an adjacent industrial park would not be a sale of steam "to or for the public" and therefore would not make WLP a steam public utility. In support of its argument, WLP notes the following: (1) the geographical, numerical and capacity limitations of its proposal, (2) the potential steam users would be able to utilize steam from other sources, including generating it for themselves, (3) the sales will occur pursuant to freely-bargained-for contracts, (4) these sales would simply involve using available steam capacity that is incidental to its production of electricity pursuant to its contract with Virginia Power, (5) the importance of the available steam as a tool to attract new industries to the industrial park and further economic growth in Halifax County, and (6) the contract would forbid the resale of the steam. In addition, WLP cites Request for Declaratory Ruling by Natural Power, Inc., and Raleigh Landfill Gas Corporation, Docket No. SP-100, Sub I (1988) (Natural Power), in which the Commission noted that steam is not as common a utility function as other services and traditionally has not been regulated to the same degree by the Commission.

The Public Staff argues that neither the Commission's Natural Power or Cogentrix decision is controlling with respect to WLP's proposed sale of steam after the termination of ROVA I's QF status. While the Commission is not pre-empted from regulating the steam sales of a QF, the fact that the production of steam for industrial process use was required for QF status was an important consideration in the Commission's Cogentrix decision. The Public Staff asserts that the standard enunciated in Simpson also must be applied to WLP's proposed steam sales to up to five industries. While the Public Staff is concerned about whether unregulated sales of steam would give WLP an unfair advantage over its potential customers, it concludes that the availability of other energy options and the fact that the sales would occur pursuant to freely-bargained-for contracts are factors in favor of finding WLP not to be a public utility. The Public Staff's major concern is the possibility that the industries to which WLP sells steam could use it to produce their own electricity. This would allow them to bypass Virginia Power. The Public Staff thus argues that the Commission should use its plenary power under G.S. 62-30 to condition WLP's certificate on selling steam solely for process use.

The Commission believes that the Simpson standard must be applied to WLP's proposed steam sales and all regulatory circumstances must be considered. The Commission noted in its Natural Power Order that steam is not as common a utility function as other services and traditionally has not been regulated to the same degree. The relatively infrequent use of steam by the general public was one of the factors that the Commission considered in Natural Power. The limited number of recipients, the geographical limitations and WLP's limited capacity do not restrict the Commission from finding WLP to be a steam utility. However, the fact that these limitations exist is a factor in favor of finding that a sale to or for the public is not involved. Other factors in favor of finding WLP not to be a public utility are the fact that WLP's steam is produced as a by-product of and incidental to its generation of electricity, the availability of other energy options to these industries, and the fact that the sales will occur pursuant to freely-bargained-for contracts.

However, if the steam being sold to the industries were used to generate electricity, WLP might be considered a utility and not be certificated because the industries would be able to bypass Virginia Power, which currently has a monopoly franchise on retail sales of electricity for this area. In Natural Power the fact that the proposed recipient of the steam would not use it to generate electricity was an important factor in our finding that Natural Power would not become a public utility by virtue of its sales of steam. The Commission notes that WLP has entered into a filed stipulation with the Public Staff that the steam it will have available for sale is of insufficient pressure for use to generate electricity. In addition, WLP has stipulated that its contract with Patch does not allow the use of the steam for such a purpose and WLP has committed to placing such a prohibition in any future contracts it signs for the sale of steam from ROVA I.

The Commission is also concerned about the use of steam for purposes other than process use, such as space heating and air conditioning, but we will not prohibit it in this order. We will monitor the use of steam for this purpose and, if justified by the circumstances surrounding a future sale of steam, may conclude that the sale of steam for this purpose is a public utility activity.

The Commission will impose certain conditions (such as a prohibition against the sale of any steam capacity in addition to the amount identified by WLP as being available for sale) and will exercise limited oversight over WLP with regard to its sale of steam. These requirements will be discussed in the next section.

As with the Commission's decision with respect to the sale of electricity, it must be emphasized that this decision turns upon the specific facts of this case and is conditioned upon the representations in WLP's Notice, Request, the Stipulation and current law. No precedent is being established that will be applied automatically to an application by an EWG or any other person in the future. The Commission does not announce any policy or intentions with respect to such future applications and will deal with each application and specific fact situation as it is presented.

NOTICE OF AMENDED INFORMATION

Commission Rule R1-37 requires certificate holders to advise the Commission of changes in the information in their applications and states that the Commission "will order such proceedings as it deems appropriate to deal with such ... changes." The certificate issued to ROVA I in 1990 was based upon the representations in WLP's application, including ROVA I's status as a QF. We must now consider how to deal with the termination of QF status and the assumption of EF status.

The Commission ruled in Empire that QF status under PURPA essentially establishes the "public need" under G.S. 62-110.1. The Commission also ruled in

Empire that a non-QF proposing to sell its electricity to a North Carolina electric utility must first obtain and allege as part of its certificate application either a contract or a written commitment from the utility. WLP has met this requirement by attaching its contract with Virginia Power and a letter from Virginia Power stating that the Power Purchase Agreement between it and WLP allows ROVA I to cease being a QF after the commercial operations date and become an EF owned by an EWG and that Virginia Power will continue to purchase electric power from ROVA I in accordance with the terms of the agreement after the conversion to EF status.

The Public Staff has stated a number of concerns about the contract between Virginia Power and WLP, particularly the way in which ROVA I's total costs have been split between its capacity and energy payments. While some changes to the original contract were negotiated after it was assigned to WLP, the final capacity and energy payments provided for in WLP's contract are not representative of conventional coal-fired technology. Under the terms of the contract, the majority of WLP's fuel costs will be recovered through the capacity payment. Because Virginia Power economically dispatches based on a facility's fuel and variable O&M (energy) payment, WLP will be dispatched ahead of other facilities that actually have lower energy costs. The Public Staff stated that it preferred that Virginia Power not enter into any contracts of this nature in the future and noted that its recommendation regarding WLP's certificate does not constitute approval of the contract. Despite the unconventional split of the costs between capacity and energy payments, the Public Staff stated that it believed that the penalties provided for in the contract should adequately protect Virginia Power's ratepayers. The Commission notes that this can be monitored in Virginia Power's future rate cases.

The stipulations WLP entered into with the Public Staff, which have been filed in Docket No. SP-77, include the following: (1) The capacity/energy split in WLP's contract is not representative of ROVA I's technology, (2) the Commission's recognition of WLP as an EWG and reissuance or amendment of ROVA I's certificate as an EF does not constitute approval of its contract with Virginia Power and in no way affects the certificate granted to ROVA II, (3) the contract between WLP and Patch Rubber Company provides that Patch can only use the steam it purchases from WLP's ROVA I plant for purposes other than producing electricity and cannot resell steam, (4) future contracts with industrial entities for the sale of steam from ROVA I will prohibit the use of steam for the production of electricity and the resale of steam, and (5) WLP will meet certain reporting requirements.

The Commission concludes that no further public notice should be required. WLP published the public notice required by the Commission before it obtained its current ROVA I certificate. The only change that has occurred or will occur is in the status of the facility under federal law, notice of which has been published in the Federal Register.

Based on the foregoing, the Commission concludes that the public convenience and necessity justify the re-issuance of WLP's certificate for ROVA I based on the representations in WLP's Notice and the Stipulation. As stated previously, the Commission will condition the re-issuance of this certificate on various restrictions and requirements being met. The Commission clearly has authority to do this. The Commission's authority under G.S. 62-110.1 extends to "persons" other than public utilities to the extent necessary for the Commission to properly discharge its duties in administering the provisions of Chapter 62. The

Commission thus has the authority to establish filing requirements for persons filing applications for certificates, to condition certificates in any way that the General Assembly's enunciated public policies require, and to otherwise act as necessary to administer Chapter 62. The Commission historically has exercised such authority. It has adopted Rule R1-37 to govern the filing and content of applications filed by QFs and it has issued conditional certificates to QFs whenever circumstances required that a particular condition be imposed. See also G.S. 62-30 and 62-31.

The public policies embodied in Chapter 62 and the regulatory circumstances of this case require that the Commission reissue WLP's certificate for ROVA I subject to a requirement that the electricity generated therefrom be used solely for resale to Virginia Power subject to its current contract and that some limited oversight over WLP and its sale of electricity be maintained. Such oversight is contemplated by the EPACT. Section 714, 16 U.S.C. 824(g), provides state commissions broad rights of access to examine the books, accounts, memoranda, contracts and records of any EWG selling electricity to a regulated public utility and of any electric utility or holding company that is an associate or affiliate of an EWG, if such examination is required for the effective discharge of the commission's regulatory responsibilities affecting the provision of electric service.

WLP's re-issued certificate is also conditioned upon WLP's filing the reports to which it has stipulated, all other stipulations, and the representations contained in WLP's Notice. The Commission also concludes that WLP's certificate should be conditioned upon the requirements that the contract between WLP and Patch Rubber Company provide that Patch can only use the steam it purchases from WLP's ROVA I plant for purposes other than producing electricity and cannot resell it, that future contracts with industrial entities for the sale of steam from ROVA I prohibit the use of steam for the production of electricity and the resale of steam, that WLP not increase the amount of steam available for sale from ROVA I, and that WLP meet certain reporting requirements with respect to steam, all the other stipulations, and the representations contained in WLP's Notice.

IT IS, THEREFORE, ORDERED as follows:

1. That based upon the facts and representations as set forth herein and in WLP's Request and subject to the Stipulation and the conditions imposed herein, WLP should not be regarded as a public utility within the meaning of G.S. 62-3(23)a and

2. That based upon the facts and representations as set forth herein and in WLP's Notice and subject to the Stipulation and the conditions imposed herein, the certificate of public convenience and necessity previously issued to WLP in Docket No. SP-77, should be, and hereby is, reissued in accordance with the terms and conditions set forth herein and the reissued certificate is attached hereto as Appendix A.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. SP-77

Know All Men By These Presents, That

WESTMORELAND-LG&E PARTNERSHIP
c/o Westmoreland Energy, Inc.
300 Preston Avenue, 5th Floor
Charlottesville, VA 22902

is hereby reissued this

CERTIFICATE OF PUBLIC CONVENIENCE
AND NECESSITY PURSUANT TO G.S.62-110.1

authorizing a coal-fired generating
facility with a capacity of 165 Megawatts
to be known as Roanoke Valley I Project

located

near Roanoke Rapids and Weldon,
Halifax County, North Carolina

subject to the reporting requirements of G.S. 62-110.1(f); to the requirements of Commission Rule R1-37(d); and also to all other orders, rules, regulations and conditions as are now or may hereafter be lawfully made by the North Carolina Utilities Commission, including those requirements set forth in the Commission Order of October 13, 1993 in Docket Nos. SP-77 and SP-100, Sub 2.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-3, SUB 181

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Application of Pennsylvania & Southern Gas Company (P&S) and NUI Corporation (NUI) for the Approval of an Agreement Merging P&S with and into NUI, with NUI as the Survivor Corporation, and for the Transfer to NUI of all of P&S's Rights and Authorities to Offer, Render, Furnish, or Supply Natural Gas Service, and for the Commencement of Natural Gas Service by NUI, and for the Abandonment of Gas Service by P&S, upon the Consummation of the Merger	ORDER APPROVING MERGER

HEARD IN: The Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on November 8, 1993

BEFORE: Commissioner Laurence A. Cobb, Presiding; Commissioners William W. Redman, Jr., and Judy Hunt

APPEARANCES:

For the Applicants:

Jerry W. Amos, Brooks, Pierce, McLendon, Humphrey & Leonard, L.L.P., Post Office Box 26000, Greensboro, North Carolina 27420

For the Public Staff:

Gisele Rankin, Staff Attorney, Public Staff, North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On September 10, 1993, Pennsylvania & Southern Gas Company (P&S) and NUI Corporation (NUI) filed a joint Petition requesting the Commission to approve (1) a merger agreement under which P&S would be merged into NUI, with NUI being the surviving corporation, (2) the transfer to NUI of all of P&S's rights and authority to provide natural gas service, (3) the commencement of natural gas service by NUI in North Carolina, (4) the abandonment of natural gas service currently provided by P&S in North Carolina, and (5) the issuance of all securities that will be issued in connection with the merger, as described in the Agreement and Plan of Merger.

On October 15, 1993, the Commission scheduled this matter for public hearing and provided for public notice. The testimony of David P. Vincent, Executive Vice President and Chief Financial Officer of NUI, was filed on October 25, 1993, on behalf of the joint applicants, and the joint testimony of James G. Hoard, Supervisor of the Natural Gas Section of the Public Staff's Accounting Division, and George T. Sessoms, Jr., Director of the Public Staff's Economic Research Division, was filed on November 1, 1993 on behalf of the Public Staff.

The hearing was held as scheduled on November 8, 1993. Witness Vincent described the terms of the merger and offered his opinion as to why the merger is in the public interest. Witnesses Hoard and Sessoms requested the Commission to impose four conditions on the merger. Three of these conditions relate to the keeping of separate records, access to books and records and certain filing requirements. Witness Vincent testified that these three conditions are acceptable to the joint applicants. The fourth condition is that neither NUI nor P&S will seek to recover from North Carolina retail ratepayers an acquisition adjustment or any part of the premium over book value paid by NUI for P&S's stock. The joint applicants oppose this condition.

Based upon the verified Petition, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. P&S is incorporated under the laws of the State of Delaware and is engaged in the business of transporting, distributing and selling natural gas. It is a public utility under the laws of North Carolina and its utility operations in this State are subject to the jurisdiction of the Commission. The Commission has previously granted P&S a Certificate of Public Convenience and Necessity. P&S presently conducts its natural gas business in North Carolina through its North Carolina Gas Service Division. The North Carolina Gas Service Division serves approximately 12,300 customers located in Rockingham and Stokes Counties. P&S also conducts its natural gas business in the states of Maryland, Pennsylvania and New York.

2. NUI is a New Jersey corporation. Its principal operating subsidiary is Elizabethtown Gas Company (EGC), which was organized in 1855. EGC is also a New Jersey corporation. EGC currently operates as two divisions, the New Jersey Division doing business as EGC (the New Jersey Division) and the Florida Division doing business as City Gas Company of Florida (City Gas). The Florida Division was acquired by NUI in 1988 as a result of a merger of City Gas into EGC. As of September 30, 1992, NUI supplied natural gas through EGC to approximately 317,000 customers in New Jersey and Florida.

3. On July 27, 1993, NUI and P&S executed an Agreement and Plan of Merger. The principal terms of the Agreement and Plan of Merger may be summarized as follows:

a. P&S will be merged with and into NUI, and, at the effective time of the merger, the separate corporate existence of P&S shall cease, and NUI shall continue as the surviving corporation. Also, at the effective time of the merger, or immediately thereafter, NUI's wholly owned subsidiary, EGC, shall be merged with and into NUI. However, for at least three years after the merger, P&S will retain its independent identity as a division of NUI. At the effective time of the proposed merger, NUI will commence providing the public utility service that is currently provided by P&S.

b. The merger involves an acquisition in a "stock-for-stock" transaction, valued at approximately $17 million, or $71.50 per share of P&S stock. Under the terms of the Agreement, each P&S shareholder will receive no less than 2.4 and no more than 3.0 NUI common shares for each P&S common share held. The closing price of NUI stock on the date the Agreement was signed, July 27, 1993, was $28¾. Under the terms of the proposed "stock-for-stock" transaction, each share of NUI stock issued and outstanding immediately prior to the effective time shall remain unchanged, and each share of P&S stock which is outstanding immediately prior to the effective time shall be converted into the right to receive the number of shares of NUI stock.

c. The merger is subject to a number of conditions. Some of the more pertinent conditions include the approval by the shareholders of P&S, the truth of the representations and warranties of both parties in all material respects as of the closing date, and the authorization of all governmental entities. Approval of NUI shareholders is not required.

4. Following the merger, NUI will charge the rates then in effect in P&S's Commission-approved tariffs, including any tariffs approved by the Commission in P&S's pending general rate case in Docket No. G-3, Sub 178.

5. NUI is ready, willing, and able to assume all of the regulatory responsibilities imposed upon natural gas utilities by the North Carolina General Statutes and by the rules and regulations of the Commission.

6. The merger will offer a number of benefits to North Carolina customers, including the following:

a. The merger will enable the combined companies' operations to better serve their customers. By operating from a larger organizational base, the combined companies will be better situated to access the capital markets at a lower cost and will be better positioned to continue to fulfill successfully their obligation to serve in the post-FERC Order No. 636 environment.

b. No change in rates is proposed in connection with the merger.

c. By joining with a larger organization with better access to the capital markets, P&S will have better access to capital resources to invest in the growing infrastructure of its respective states' operations.

d. NUI and P&S operate with common interstate pipeline sources. This similarity of operating environments will help provide opportunities to improve prospective supply planning activities through increased capacity utilization opportunities. In turn, the North Carolina operations will be in a better position to secure gas supplies. Further, as a result of FERC Order No. 636, the nation's interstate pipelines will no longer perform their traditional merchant function. This responsibility will move to the local distribution companies and will thus increase the risks associated with securing reliable gas supplies and transportation services for end users. The merger will better position the combined companies to meet the prospective risks and to provide a competitive level of customer service in a changing marketplace.

e. As a good employer and a publicly oriented utility with a history dating back to 1855, NUI is committed to working with the employees of P&S in providing the best possible service at the lowest reasonable cost to the customers of P&S.

f. P&S employees will be afforded greater career opportunities within a larger organization. Increasing the breadth of employees' exposure will further improve the combined companies' capabilities. Moreover, by operating within the framework of a larger organization, each division is able to draw upon the expertise and experiences of its sister divisions.

7. NUI has agreed that it will keep the books and records for the North Carolina operations separate, that it will allow reasonable access to its books and records and those of its affiliates as required by North Carolina law, and that it will meet all of the reporting requirements and all other obligations and requirements that P&S currently is required to meet by Commission orders.

8. As of June 30, 1993, NUI's gross cost for the P&S acquisition was estimated to be $17.2 million, and the book value of P&S's net assets was approximately $9.9 million. The difference consists of a premium paid to P&S's stockholders plus transaction costs.

DISCUSSION OF EVIDENCE

The evidence supporting the findings of fact can be found in the Petition and in the testimony of NUI witness Vincent and Public Staff witnesses Hoard and Sessoms.

NUI witness Vincent testified that the merger will offer a number of benefits to North Carolina customers, and he described these benefits. The Public Staff had communicated four concerns to NUI and NUI agreed to three of the Public Staff's requests. These requests relate to keeping separate books and records for North Carolina operations, providing the Public Staff with reasonable access to its books and records and those of its affiliates as required by North Carolina law, and meeting all of the reporting requirements and other obligations required of P&S by prior Commission orders. Vincent testified that NUI could not agree to the Public Staff's fourth request, which is that neither NUI nor P&S as a separate division will seek to recover an acquisition adjustment from North Carolina retail ratepayers. He testified that ruling on this request would be premature since NUI has not requested any change in rates in this docket. He testified that he did not know whether NUI would seek an acquisition adjustment in some future rate case, but he asked that NUI not be required to waive its opportunity to do so now. He testified that many of the benefits of the proposed merger will be realized immediately upon consummation of the merger, but that other benefits which are anticipated now will not accrue until the future and cannot be quantified until well after the merger's consummation. For this reason, the difficulty or impossibility of quantifying future costs savings, NUI desires to reserve its right to make a claim for the recovery of an acquisition adjustment in a future rate case.

Witnesses Hoard and Sessoms testified for the Public Staff that the benefits described by NUI are general and have not been quantified. Still, they do not oppose the merger if all four conditions are met. They testified that the Commission must inquire into all aspects of anticipated service and rates which could result from the proposed merger, that the proposed merger creates an acquisition adjustment at the time the merger occurs and could give rise to future rate increases solely due to the change in ownership, and that unless recovery of the acquisition adjustment is disallowed now, the Public Staff does not believe the proposed merger to be in the public interest. An acquisition adjustment is the difference between the purchase price and the book value of the net assets. The purchase price is the result of negotiations and represents the market value to the purchaser of the net assets. The market value of the net assets can be more, or even less, than the book value of those net assets. The Public Staff witnesses testified that public utility ratemaking does not contemplate ratepayers being required to pay investors both the original cost of the assets and any subsequent appreciation in the market value of the assets.

CONCLUSIONS

1. The transactions herein proposed are for a lawful object within the corporate powers of the joint applicants, are justified by and compatible with the public convenience and necessity, are necessary or appropriate for and consistent with the proper performance of the joint applicants' service to the public and will not impair the joint applicants' ability to perform that service, and are reasonably necessary and appropriate for such purpose.

2. It is reasonable and appropriate to condition the merger as follows: (1) NUI shall keep separate books and records for its North Carolina operations, (2) NUI shall provide the Public Staff with reasonable access to the books and records of NUI and any NUI affiliate as required by North Carolina law, and (3) NUI shall comply with all lawful reporting requirements and other obligations and requirements that P&S is required to meet by prior Commission orders.

3. It is not reasonable or appropriate to require NUI to agree as a condition of the merger that it will not seek an acquisition adjustment in any future North Carolina rate case. NUI is not seeking to increase rates to recover an acquisition adjustment in this proceeding. If at some future date, NUI should request the Commission to permit it to increase rates to recover an acquisition adjustment, the Commission will consider that request at that time and will make its decision based on the facts and circumstances as they then exist. The Commission's decision does not prejudice any party's right to argue for or against an acquisition adjustment if the Commission is presented with the issue in a future general rate case.

IT IS, THEREFORE, ORDERED that:

1. That P&S and NUI are authorized to consummate the merger as set forth in the Agreement and Plan of Merger of July 27, 1993;

2. That NUI is authorized to issue all of the securities which will be issued in connection with the merger as provided in the Agreement and Plan of Merger;

3. That upon the consummation of the merger, all of P&S's rights and authority to provide natural gas public utility service in North Carolina pursuant to its Certificate of Public Convenience and Necessity shall be transferred to NUI, NUI shall commence natural gas public utility service in North Carolina in the areas previously certificated to P&S, and P&S shall be authorized to abandon the natural gas public utility service currently being provided by it to the public in North Carolina;

4. That upon the consummation of the merger, (1) NUI shall keep separate books and records for its North Carolina operations, (2) NUI shall provide the Public Staff with reasonable access to the books and records of NUI and any NUI affiliate as required by North Carolina law, and (3) NUI shall comply with all lawful reporting requirements and other obligations and requirements that P&S is required to meet by prior Commission orders; and

5. That within 60 days following the completion of the transactions authorized herein, NUI shall file with the Commission a verified report of all actions taken and transactions consummated pursuant to this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of December 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-3, SUB 178
DOCKET NO. G-3, SUB 180

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Pennsylvania and Southern Gas Company, North Carolina Gas Service Division, for an Adjustment of Its Rates and Charges and Application of Pennsylvania and Southern Gas Company, North Carolina Gas Service Division, for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) - 1993	ORDER APPROVING RATE DECREASE AND ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD IN: Reidsville Branch of the Rockingham Public Library System, 204 West Morehead Street, Reidsville, North Carolina, on Monday, September 20, 1993, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, September 22, 1993, at 9:30 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding; Chairman John E. Thomas; and Commissioners William W. Redman, Jr., Charles H. Hughes, Judy Hunt, and Ralph A. Hunt

APPEARANCES:

For the Applicant:

James T. Williams, Jr., and James H. Jeffries, IV, Attorneys at Law, Brooks, Pierce, McLendon, Humphrey and Leonard, Post Office Box 26000, Greensboro, North Carolina 27420

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Box 1269, Morganton, North Carolina 28655

For the Public Staff:

Antoinette R. Wike, Chief Counsel, and A. W. Turner, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On May 18, 1993, Pennsylvania and Southern Gas Company, North Carolina Gas Service Division (hereinafter P&S or Company), filed an application with the Commission in Docket No. G-3, Sub 178, for authority to adjust its rates and charges for retail natural gas service in North Carolina. The Company sought an overall decrease in rates of $212,391.

By Order issued on June 8, 1993, the Commission declared the matter to be a general rate case, suspended the proposed rates and charges, scheduled the matter for hearing in Reidsville and Raleigh, North Carolina, and required the Company to give notice of its application to the public.

On June 8, 1993, the Carolina Utility Customers Association, Inc. (CUCA), petitioned to intervene in the rate case. The petition was granted on June 10, 1993.

On July 22, 1993, the Public Staff filed a stipulation between it and the Company regarding rate of return and capital structure.

On July 1, 1993, P&S filed testimony in its annual cost of gas review, Docket No. G-3, Sub 180. On August 2, 1993, the Company moved to join the two cases for hearing, and on August 4, 1993, the Commission granted that motion.

On August 25, 1993, CUCA petitioned to intervene in the Sub 180 case. That petition was granted on August 30, 1993.

A public hearing was held in Reidsville for the specific purpose of receiving testimony from public witnesses. One public witness, William Markham, a residential customer, testified.

The case in chief came on for hearing as scheduled in Raleigh. The Company presented the testimony of Bernard L. Smith, Treasurer and Controller of P&S, and James W. Carl, Vice-President for P&S.

The Public Staff presented the testimony of Jeffrey L. Davis, Engineer, Natural Gas Division, Jan A. Larsen, Engineer, Natural Gas Division, and Julie Ann Grimsley, Staff Accountant, Accounting Division.

Based upon the verified application, the Commission's records, the testimony and exhibits received into evidence in this proceeding, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

GENERAL MATTERS

1. P&S is duly organized as a corporation under the laws of the State of Pennsylvania and is duly authorized to do business in the State of North Carolina. Its North Carolina operation's office is located in Reidsville, North Carolina.

2. P&S is a public utility engaged in the business of transporting, distributing, and selling natural gas at retail in a service area consisting of Rockingham County, North Carolina, and part of Stokes County, North Carolina.

3. P&S is subject to the jurisdiction of the North Carolina Utilities Commission, and is lawfully before this Commission upon its application for an adjustment in its rates and charges for natural gas service pursuant to G.S. 62-133, as well as P&S's annual review of its gas costs under G.S. 62-133.4(c) and NCUC Rule R1-17(k)(6).

4. P&S is providing an adequate quality of natural gas service to its customers.

5. P&S originally requested a decrease in annual revenues of $212,391, which consisted of (1) an increase in non-gas costs of $391,199, and (2) a decrease in rates due to the overcollection of fixed gas costs of $603,590.

6. The test period for this rate case is the 12 months ended December 31, 1992. The test period for the gas cost review is the 12 months ended April 30, 1993.

7. Prior to the hearing, the Company and the Public Staff settled the issues on which they had differed. The Public Staff filed testimony and exhibits on September 2, 1993, reflecting the stipulations and agreements reached between the two parties. The Company filed a letter with the Commission on September 16, 1993, agreeing with the testimony and exhibits of the Public Staff.

VOLUMES

8. The appropriate level of adjusted sales and transportation volumes for use in this case is 3,541,251 dekatherms (dts). This number does not include Company use or unaccounted for volumes.

9. Actual test period sales and transportation volumes were 3,454,991 dts.

10. Actual test period volumes should be adjusted to reflect normal weather conditions.

11. Under the facts and circumstances of this case, it is proper to reflect growth in sales and transportation volumes through September 30, 1993, to obtain a proper matching of revenues and plant.

12. The appropriate volume level for lost and unaccounted for gas is 77,063 dts.

13. The appropriate level of Company use gas is 438 dts.

14. The gas supply required to satisfy the appropriate sales level is as follows:

	Dekatherms
Sales and transportation	3,541,251
Company use	438
Lost and unaccounted for	77,063
Gas supply	3,618,752

COST OF GAS

15. The appropriate level for total fixed cost of gas is $2,229,468.

16. It is appropriate to classify producer reservation fees as a commodity cost of gas item.

17. The total commodity cost of gas is $9,046,880.

18. The appropriate cost of Company use gas is $986.

19. It is proper to reclassify Company use gas from Cost of Gas expense to Operation and Maintenance (O&M) expenses.

20. The reasonable level for the total cost of gas is $11,276,348, determined as follows:

Commodity cost of gas	$ 9,046,880
Fixed cost of gas	2,229,468
Total cost of gas	$11,276,348

RATE BASE

21. The appropriate level of gas utility plant in service for use in this proceeding is $14,363,151.

22. The appropriate level of accumulated depreciation for use in this proceeding is $3,999,219.

23. The appropriate level of gas in storage for use in this proceeding is $520,627.

24. Gas in storage should be priced at the current rolling average prices.

25. The appropriate level of materials and supplies for use in this proceeding is $235,160.

26. The appropriate level of cash working capital is $396,031.

27. For purposes of this proceeding, customer deposits of $79,126 and tax accruals of $218,026 should be deducted from working capital.

28. It is appropriate to include the level of cost-free capital related to pensions as proposed by the Public Staff in this proceeding of $189,878.

29. The appropriate level of accumulated deferred income taxes for use in this proceeding is $985,300.

30. P&S's reasonable original cost rate base used and useful in providing service is $10,043,420, consisting of gas plant in service of $14,363,151, gas in storage of $520,627, materials and supplies of $235,160, and cash working capital of $396,031, reduced by accumulated depreciation of $3,999,219, pension related cost-free capital of $189,878, tax accruals and customer deposits of $297,152, and accumulated deferred income taxes of $985,300.

OPERATING REVENUES

31. The appropriate level of end-of-period revenues for use in this proceeding is $17,443,093, which is comprised of $17,426,607 of sales and transportation revenues and $16,486 of miscellaneous revenues.

32. It is appropriate to reflect revenues associated with customer growth through September 1993.

OPERATING REVENUE DEDUCTIONS

33. The appropriate level of operation and maintenance expenses for use in this proceeding is $3,168,245.

34. It is appropriate to include a reasonable level of uncollectibles expense of $18,763.

35. The appropriate level of regulatory fee expense is calculated based on end-of-period revenues using the effective rate of .085%.

36. For purposes of this proceeding, it is appropriate to annualize payroll expenses for salary levels in effect at the end of the test year.

37. Payroll expenses should be updated and annualized to reflect the payroll increases effective as of October 1, 1993, for known and measurable changes authorized by the Company's Board of Directors.

38. It is appropriate to allocate the updated payroll costs to North Carolina utility O&M expenses using the four factor allocation percentage of 43.29% for Pennsylvania general office salaries and 69.93% for North Carolina salaries.

39. It is appropriate to reflect in O&M expenses one-third of the non-recurring legal and accounting expenses associated with the arbitration case which occurred during the period.

40. The appropriate amount for legal and accounting costs to reflect in O&M expenses associated with the arbitration case is $9,859.

41. It is appropriate to reflect in O&M expenses one-third of the estimated rate case expenses associated with this rate case.

42. The appropriate amount of rate case expenses to reflect in O&M expenses is $7,791.

43. The appropriate level of post-retirement benefits cost reflected in O&M for purposes of this proceeding is $32,241.

44. It is appropriate to capitalize a portion of post-retirement benefits cost based on the payroll distribution.

45. The appropriate level of depreciation expense for use in this proceeding is $516,286.

46. Based on other findings and conclusions set forth in this Order, the appropriate level of general taxes for use in this proceeding is $743,062.

47. For purposes of this proceeding, property taxes should be updated for plant additions found reasonable through September 30, 1993.

48. It is appropriate to update payroll taxes for payroll increases effective October 1, 1993, as authorized by the Company's Board of Directors.

49. Based on the other findings and conclusions set forth in this Order, the appropriate level of state income tax expense under present rates for use in this proceeding is $103,507.

50. The weighted rate for the state income tax surtax is 1% based on an average for the fiscal years ending September 30, 1994, 1995, and 1996. This results in an overall state income tax rate of 7.8275%.

51. Based on other findings and conclusions set forth in this Order, the appropriate level of federal income tax expense under present rates for use in this proceeding is $399,047.

52. It is appropriate to reflect $5,750 for the amortization of excess deferred income taxes in the calculation of federal income taxes.

53. It is appropriate to reflect $9,609 for the amortization of investment tax credits in the calculation of federal income taxes.

54. The overall level of operating revenue deductions under present rates appropriate for use in this proceeding is $16,206,496.

CAPITAL STRUCTURE AND COST OF CAPITAL

55. The Company and the Public Staff filed a stipulation with the Commission on July 22, 1993, relating to the capital structure and cost of capital.

56. The proper capital structure appropriate for use in this proceeding is as follows:

	Amount	%
Debt	$ 5,021,710	50.0
Common equity	5,021,710	50.0
Total	$10,043,420	100.0

57. The proper cost of long-term debt is 8.30%

58. The Company and the Public Staff agreed in the stipulation to a return on common equity of 11.90%. No other party presented evidence on the appropriate return on common equity.

59. Based on the stipulation with respect to the proper capitalization ratios and the appropriate cost rates for each component of capital reflected in that capitalization, the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 10.10%.

REVENUE REQUIREMENT

60. P&S should be authorized to decrease its annual level of operating revenues by $377,761. After giving effect to the approved decrease, the annual revenue requirement for P&S is $17,065,332, which will allow the Company a reasonable opportunity to earn the return on common equity which the Commission finds to be just and reasonable.

GAS - RATES

CUSTOMER ATTACHMENT FEE

61. A customer attachment fee is appropriate for new residential and commercial customers and should be set at $15 per additional customer.

62. The estimated revenue from customer attachment fees is $6,576.

COST OF SERVICE AND RATE DESIGN

63. P&S and the Public Staff are the only parties that performed and presented estimated cost-of-service studies.

64. The principal differences between the cost-of-service studies prepared by P&S and the Public Staff relate to different levels of revenues, volumes, plant investment and expenses and to the use of different allocation factors.

65. While estimated cost-of-service studies are subjective and judgmental, they are useful as a guide in designing rates.

66. Rates based solely on one or more estimated cost-of-service studies are not reasonable for purposes of this proceeding.

67. Rates based entirely upon equalized rates of return among customer classes are not reasonable for purposes of this proceeding.

68. A number of factors must be considered when rates are designed. These factors include the cost of service; the value of service to the customer; and type and priority of service received by the customer and, if the service is interruptible, the frequency of interruptions; the quantity of use; the time of use; the manner of service; the competitive conditions in the market place related to the acquisition of new customers; the historic rate differentials between the various classes of customers; the revenue stability of the utility; and the economic and political factors which are inherent in the ratemaking process, including the encouragement of expansion.

69. P&S's residential customers have a very limited ability to switch to alternate fuels without making significant capital investment in new equipment. In addition, they bear the risk of being required to make up margin losses resulting from P&S's negotiations with industrial customers.

70. Industrial customers have the ability to switch to alternate fuels and therefore have the ability to negotiate rates.

71. The ability of the large commercial and industrial customers to negotiate and force P&S to meet the prices of their alternative fuels gives them bargaining power not enjoyed by other classes of customers. This justifies a higher rate of return for these customers.

72. The large commercial and industrial customers receive a relatively high value of service that has to be taken into account in addition to any estimated cost-of-service studies. They also have interruptible service, but very few interruptions, which justifies a higher rate of return.

73. Because the rates of the residential class of customers have increased in the past while the industrial rates have decreased, the residential class has been paying a steadily increasing percentage of P&S's non-gas costs.

74. The Commission has historically concluded (and has subsequently been upheld by the North Carolina Supreme Court) that the factors listed in Finding of Fact No. 68 are appropriate for consideration in designing rates.

75. In determining rate design for a specific class, the Commission considers the utility's historic rate design as well as other relevant facts and circumstances

76. Although estimated cost-of-service studies are subjective, it would not be appropriate for purposes of this proceeding to set rates for customers on Rate Schedule 101 that would yield a negative rate of return.

77. Because of the historic increases in residential rates and decreases in industrial rates in P&S's last two general rate cases and considering the fact that this proceeding involves an overall revenue decrease for P&S, it would be unreasonable to either increase or decrease the rates under Rate Schedule 101 in this proceeding.

78. For purposes of this proceeding, rates should be designed so that the $5,670,450 in revenues from rates collected under Rate Schedule 101 shown in column (B) of Davis Exhibit E remain constant.

79. The $39,540 decrease in Rate Schedule 101 revenues shown in column (D) of Davis Exhibit E shall be allocated to the other customer classes proportionally using the total rate base shown on line 32 of Larsen Exhibit B as a weighting factor.

80. The facilities charge for customers on Rate Schedule 101 shall remain at $6.00 per month.

81. The miscellaneous service charges as proposed by the Company and set forth in Appendix A are just and reasonable.

FIXED GAS COST RECOVERY RATES

82. The Public Staff's methodology of allocating fixed gas costs results in fixed gas cost recovery rates that range from $1.1097/dt for Rate Schedule 101 to $.2972/dt for Rate Schedule 105.

83. The fixed gas costs recovery rates proposed by the Public Staff are appropriate for purposes of calculating fixed gas cost recovery in Rider D and for the functioning of the Weather Normalization Adjustment factor approved in this Order.

TRANSPORTATION RATES

84. The Commission has approved full margin transportation rates for all of the natural gas local distribution companies operating in North Carolina.

85. The Commission has consistently calculated full margin transportation rates by subtracting the annual cost of gas, applicable gross receipts taxes, and any temporary increments or decrements from the sales rate schedule under which the transportation customer would otherwise be buying natural gas from P&S.

86. The basic premise underlying the concept of full margin transportation rates as previously approved by the Commission is that the LDC should be neutral as to whether a customer transports or buys natural gas under a filed tariff rate. For an LDC to be neutral, a transportation customer should pay the same fixed costs it would pay as a sales customer.

87. The services performed by P&S for a customer who transports are substantially the same as those performed for a sales only customer.

88. The full margin transportation rates resulting from the adoption of the Public Staff's recommended methodology are just and reasonable.

WEATHER NORMALIZATION ADJUSTMENT

89. P&S has requested approval of a Weather Normalization Adjustment (WNA) which will reduce variations in the Company's earnings and otherwise protect the Company from the adverse impacts of departures from normal weather.

90. The WNA will be in effect for the winter period for Rate Schedules 101 and 102.

91. P&S's WNA should operate in the same manner as the Weather Normalization Adjustment clause recently approved for Piedmont Natural Gas Company, Public Service Company of North Carolina, and North Carolina Natural Gas Corporation.

92. The R_i factors appropriate for use in the WNA formula are as proposed by the Public Staff on Davis Exhibit F, adjusted for the change in winter rates as calculated per ordering paragraph number 7 of this Order.

93. The heating degree day data base as kept by the Public Staff is appropriate and accurate for use in determining the long-term normal degree day average in the WNA formula.

94. Industrial customers on Rate Schedule 102 that are determined to be non-heat sensitive may be excluded from the WNA mechanism after one year of experience.

RULES AND REGULATIONS

95. P&S's proposed service regulations as amended by the Public Staff and agreed to by the Company are just and reasonable.

96. P&S has filed with the Commission and submitted to the Public Staff all of the information required by North Carolina General Statute 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

97. The test period for the annual review of gas costs is the twelve months ended April 30, 1993.

98. During the review period, P&S incurred fixed gas costs of $2,124,803 and collected $2,565,435 in revenues attributed to those costs.

99. Commodity costs incurred during the review period were $8,286,483 and exceeded amounts collected for the period by $98,444.

100. P&S has properly accounted for its gas costs during the review period and the journal entries are proper.

101. P&S has made prudent gas purchasing decisions and all of the gas costs incurred by P&S during the review period were prudently incurred.

102. P&S acquired no new capacity during the review period.

103. The balance in the deferred account at the twelve months ended April 30, 1993, relating to the all customers account is $583,957. This amount should be refunded to all sales and transportation customers by placing a temporary decrement in those rates of $.1649/dt.

104. The balance in the deferred account at the twelve months ended April 30, 1993, relating to the sales only account is $220,650. This amount should be refunded to all sales customers by placing a temporary decrement in those rates of $.0623/dt.

105. It is just and reasonable to continue the temporary decrement in rates as prescribed in the above findings until further order of the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-6

The evidence supporting these findings of fact is contained in the verified application, the testimony and exhibits of the Public Staff and Company witnesses in this case, and the Commission's records. These findings of fact are essentially informational and uncontradicted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding is contained in the testimony filed by the Public Staff and a letter filed by P&S with the Commission on September 16, 1993. In addition, Company witness Carl and the Public Staff witnesses indicated at the time they introduced their prefiled testimony and exhibits that they assented to the stipulation, and witness Carl testified that the stipulation should supersede his prefiled positions. The agreement between the Company and the Public Staff reflected in their testimony and the Company's letter will be referred to hereinafter as "the stipulation," but except for the written stipulation on rate at return and capital structure, there was no formal written stipulation betwen the Company and the Public Staff in this case.

CUCA did not join in the stipulation but did not oppose the revenue requirement issues. The Commission has considered the stipulation along with all other testimony and exhibits received at the hearing. The Commission has weighed the terms of the stipulation in the context of the entire record, and the Commission has proceeded to determine the Company's rates under the standards of G.S. 62-133 and other applicable statutes on the basis of the entire record.

The Commission concludes that the stipulation between the Public Staff and the Company, except as otherwise provided herein, is appropriate for this proceeding.

The Commission concludes that the test period and the post-test year updates stipulated between the Company and the Public Staff are appropriate for use herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-14

The evidence supporting these findings is found in the Company's application, in Company witness Carl's testimony and exhibits, in Public Staff witness Davis' testimony and exhibits, and in the record as a whole.

In prefiled testimony, witness Carl testified to different pro forma gas sales and transportation volume levels. Prior to hearing, the Company and Public Staff stipulated to the volume levels.

The Company and Public Staff agreed that the actual test period sales and transportation volumes were 3,454,991 dekatherms before adjustments. Both parties further agreed that after adjustments for weather normalization, customer underbillings, customer reclassifications, and customer growth through September 31, 1993, the appropriate level of sales and transportation volumes should be 3,541,251 dekatherms as shown on Davis Exhibit A. No other evidence on the appropriate volume level was presented.

The Company and Public Staff also agreed that the appropriate level of lost and unaccounted for volumes is 77,063 dekatherms and 438 dekatherms for Company use gas. Witness Davis testified that the Public Staff was recommending the continuance of the true-up of these volumes annually based on the actual twelve-month cumulative volumes at June of each year as compared to the level of volumes included in this rate case.

The level of sales and transportation volumes, in addition to the lost and unaccounted for and Company use volumes, will require purchases of annual gas supply amounting to 3,618,752 dekatherms as shown on Davis Exhibit C.

Based upon the evidence, the Commission finds that the appropriate level of sales and transportation volumes for determining end-of-period and proposed revenue levels is 3,541,251 dekatherms.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-20

The evidence for these findings of fact is contained in the testimony and exhibits of Public Staff witnesses Davis and Grimsley.

Company witness Carl testified that due to the stipulation with the Public Staff, the testimony and exhibits of the Public Staff reflect all of the agreements.

Based upon the evidence, the Commission finds that the uncontested level for the total cost of gas for use in setting rates in this proceeding is $11,276,348. This cost of gas is comprised of $9,046,880 in commodity costs and $2,229,468 in fixed gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The Company offered evidence that plant in service at December 31, 1992, was $13,678,383. In its initial filing, the Company proposed to increase plant in service by $788,101 to reflect estimated plant additions through September 30, 1992. Public Staff witness Grimsley proposed in her prefiled testimony to increase plant in service for post-test year plant additions, net of retirements, by $684,769 to recognize the addition of actual plant additions through August 31, 1993, and estimated additions for September 1993. This adjustment had the effect of reducing plant in service by $103,332.

In the stipulation, the Company and the Public Staff agreed to the level of gas plant in service of $14,363,151 found in Public Staff witness Grimsley's prefiled testimony.

The Commission concludes that the gas plant in service stipulated between the Company and the Public Staff are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The Company offered evidence that accumulated depreciation at the end of the test period was $3,727,034. The Company proposed to increase this amount by $487,054 to reflect the adjustment to depreciation expense (1) for the approved change in depreciation rates and (2) to reflect the adjustments related to plant additions and retirements. Through prefiled testimony and exhibits of Public Staff witness Grimsley, the Public Staff proposed to reduce pro forma accumulated depreciation by $214,869. This adjustment reflects the Public Staff's reversal of the Company's adjustment to accumulated depreciation for depreciation rate changes of $95,187 because it had already been incorporated into the prefiled testimony and exhibits of witness Grimsley. The $214,869 adjustment also incorporates retirements as well as plant additions into the calculation of accumulated depreciation through September 1993.

In the stipulation, the Company agreed to the Public Staff's level of accumulated depreciation. No other party offered any evidence on this issue.

The Commission concludes that the accumulated depreciation stipulated between the Company and the Public Staff is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-24

The Company offered evidence that the appropriate level of gas in storage is $461,709 at the end of the test period. Public Staff witness Grimsley proposed to price the gas in storage inventory at the current rolling average inventory prices to determine the Company's actual investment. After the Public Staff adjustments, the gas in storage inventory would be $520,627. In the stipulation, the Company agreed to the Public Staff's adjustment. No other party offered any evidence on this issue.

The Commission concludes that the level of gas in storage stipulated between the Company and the Public Staff is appropriate for use in this case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The Company offered evidence that the appropriate level of materials and supplies for use in this proceeding is $235,160. The Company did not propose any pro forma or accounting adjustments. The Public Staff did not propose any adjustments to materials and supplies. No other party offered any evidence on this issue.

The Commission concludes that the level of materials and supplies reflected in the Company's application and the Public Staff's prefiled testimony and exhibits above is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The Company offered evidence that cash working capital should be $393,410. The Public Staff proposed adjustments to cash working capital. These adjustments would increase cash working capital to $396,031. The Company and the Public Staff agreed to this level of cash working capital in the stipulation. No other party offered any evidence on cash working capital.

The Commission concludes that the level of cash working capital stipulated between the Company and the Public Staff is appropriate for use in this case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-28

The Company proposed to reduce rate base by $79,126 for customer deposits and $218,026 of tax accruals. Public Staff witness Grimsley did not propose to adjust the level of customer deposits and tax accruals represented by the Company. No other party offered any evidence on customer deposits and tax accruals.

The Company did not include an amount for cost-free capital related to pensions. The Public Staff proposed to recognize cost-free capital resulting from the excess of pension expense over pension plan contributions. After the adjustment, cost-free capital would be $189,878. In the stipulation, the Company and the Public Staff agreed to the level of cost-free capital represented by the Public Staff.

The Commission concludes that the level of customer deposits, tax accruals, and pension related cost-free capital stipulated between the Company and the Public Staff is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The Company offered evidence that the appropriate level of accumulated deferred taxes is $961,036. Public Staff witness Grimsley proposed to adjust accumulated deferred income taxes by $24,264 to reflect Company updates through September 1993. After the Public Staff's adjustments, the accumulated deferred taxes are $985,300. In the stipulation, the Company agreed to the Public Staff's adjustment. No other party offered any evidence on this issue.

The Commission concludes that the accumulated deferred taxes stipulated between the Company and the Public Staff is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The rate base equals gas plant in service less accumulated depreciation plus the sum of gas in storage, materials and supplies, and cash working capital, less customer deposits and tax accruals, pension related cost-free capital, and accumulated deferred income taxes.

The Commission, after considering all of the evidence set forth above, concludes that the unchallenged rate base for use in setting rates in this proceeding is $10,043,420 as shown in the following chart:

Item	Amount
Gas utility plant in service	$14,363,151
Accumulated depreciation	(3,999,219)
Net plant in service	10,363,932
Gas in storage inventory	520,627
Materials and supplies	235,160
Cash working capital	396,031
Customer deposits	(79,126)
Tax accruals	(218,026)
Pension related cost-free capital	(189,878)
Accumulated deferred income taxes	(985,300)
Rate base	$10,043,420

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-32

The evidence for these findings of fact is found in the testimony and exhibits of Public Staff witnesses Grimsley and Davis.

Witness Davis testified that the volume level as stipulated to, priced out at the present Commission approved rates, excluding any temporaries, results in end-of-period revenues of $17,426,607. This figure reflects customer growth through September 1993. Witness Grimsley testified that the appropriate level of miscellaneous revenues is $16,486. Both witnesses testified that the total revenue level at present rates is $17,443,093.

This issue was uncontested and no other party presented testimony on revenues under present rates.

Therefore, the Commission concludes that the appropriate revenue level under present rates priced at the volume level of 3,541,251 dekatherms is $17,443,093.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33-44

The Company offered evidence that actual operation and maintenance expense during the test period was $2,983,322. The Company proposed annualizing and pro forma adjustments of $163,955.

Public Staff witness Grimsley questioned the treatment of the following items in the Company's pro forma operation and maintenance expense: (1)

uncollectibles, (2) regulatory fee, (3) calculation of annualized payroll expenses, (4) authorized payroll increases effective October 1, 1993, (5) level of payroll applicable to operations, (6) amortization of legal and accounting expenses related to arbitration case, (7) rate case expense (8) the level of postretirement benefit costs, and (8) postretirement benefit costs applicable to operation and maintenance expense.

Uncollectibles

The Company included uncollectibles of $32,560 in its original filing. The Company computed uncollectibles based on a percentage of total revenues. The Public Staff proposed uncollectibles of $18,763. The Public Staff computed uncollectibles based on actual bad debts or actual charge-offs for the year minus the previously written off bad debts that had been subsequently collected during the year. In the stipulation, the Company agreed to the Public Staff's adjustment. No other party offered any evidence on the calculation of uncollectibles.

Regulatory Fee

The Company did not propose to update the regulatory fee for increased revenues in its original filing. The Public Staff computed the regulatory fee by applying the statutory percentage of .085% effective at the time of the hearing to the revenue adjustments proposed by the Public Staff. In the stipulation, the Company agreed to the Public Staff's adjustments.

Payroll Expense

The Company proposed to include an annualized level of payroll expenses based on salary levels as of December 31, 1992. The Company's calculation did not represent a full year of annual payroll costs. The Public Staff proposed to increase the payroll costs to reflect an accurate annualized cost.

Additionally, the Company represented that P&S had projected payroll increases through October 1, 1993, as authorized by the Board of Directors. The Public Staff agreed to update the salary levels through October 1, 1993, for known and measurable increases in annual payroll costs. The Public Staff then applied North Carolina O&M expense allocations to these updated North Carolina and general office payroll levels which resulted in an $87,831 adjustment to payroll expenses. In the stipulation, the Public Staff and the Company agreed to the payroll expense level.

Arbitration Case

Public Staff witness Grimsley proposed to amortize the accounting and legal fees related to an arbitration case involving two employees during the test year. This amortization reduced the level of operation and maintenance expenses over a three-year period. The Public Staff proposed that because these expenses were non-recurring, the total level should not be included. In the stipulation, the Company accepted the annual level of legal and accounting expenses related to the arbitration case of $9,859. No other party contested this adjustment.

Rate Case Expense

Public Staff witness Grimsley proposed to reduce the Company's pro forma rate case expense to remove the unamortized balance of rate case expenses from the Company's last general rate case. In the stipulation, the Company agreed to the Public Staff's adjustment. Both the Public Staff and the Company agreed to use a three-year amortization period for rate case expense. The Company agreed to the Public Staff's proposed rate case expense amount of $7,791, and no party contested that figure.

Postretirement Benefit Costs

It is appropriate to recognize that the Financial Accounting Standards Board issued Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106), which requires employers to accrue and recognize for financial reporting purposes all costs associated with postretirement benefits other than pensions (PBOPs).

The Company offered evidence in its initial filing that the expected level of postretirement benefit costs effective October 1, 1993, for P&S's North Carolina operations is $74,026. The Company proposed a pro forma adjustment of $66,916 to cover additional accrued SFAS 106 costs above the test year cash basis or "pay as you go" costs. The Company subsequently updated its position on postretirement benefit costs for North Carolina operations to reflect an annual level of $64,166. The Public Staff accepted this amount and also proposed to capitalize a portion of the postretirement benefit costs consistent with the payroll distribution for the test period. In the stipulation, the Company and the Public Staff agreed that the proper O&M expense level of postretirement benefit costs for North Carolina operations is $43,096. No other party offered any evidence as to the appropriate level of postretirement benefit costs.

Summary Conclusion

The Commission concludes that the level of operation and maintenance expense, which incorporates the adjustments set forth above in the stipulation between the Company and the Public Staff, of $3,168,245 is appropriate for this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45

The Company offered evidence that actual depreciation expense during the test period was $400,003. The Company proposed annualizing and pro forma adjustments of $115,804. The Company reflected these adjustments for depreciation rates that changed during the test year and for post-test year additions and retirements.

Public Staff witness Grimsley proposed to update the Company's depreciation expense level for estimated plant additions and retirements through September 1993. In the stipulation, the Company and the Public Staff agreed that the proper level of depreciation expense is $516,286. No other party offered any evidence as to the appropriate level of depreciation expense.

The Commission concludes that the level of depreciation expense stipulated between the Company and the Public Staff is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 46-48

The Company offered evidence that the actual level of general taxes during the test period was $638,491. The Company proposed pro forma and accounting adjustments of $69,143. The Company contended that these adjustments are necessary to (1) increase payroll taxes to the going level basis and (2) increase gross receipts taxes consistent with the adjustments to revenues.

Public Staff witness Grimsley proposed to increase the Company's pro forma general taxes by $24,941 to reflect the revenue adjustments proposed by the Public Staff. Witness Grimsley also increased the Company's pro forma general taxes by $10,485 to reflect the Public Staff's adjustments to payroll increases authorized by the Board of Directors as of October 1, 1993, as well as, updated property taxes related to the post-test year additions through September 30, 1993.

In the stipulation, the Company and the Public Staff agreed that the proper level of general taxes is $743,062. No other party offered any evidence as to the appropriate level of general taxes.

The Commission concludes that the level of general taxes found reasonable in the stipulation between the Company and the Public Staff is appropriate for this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-53

State Income Taxes

The Company offered evidence that the actual level of state income taxes during the test period was $64,381. The Company proposed accounting, annualizing, and pro forma adjustments of $(16,717). The Company contended that this adjustment is necessary to reflect a computation of state income taxes after the pro forma, annualizing, and accounting adjustments.

Public Staff witness Grimsley proposed to increase the Company's pro forma state income taxes by $55,842 to reflect the Public Staff's adjustments to cost of gas, changes in fixed charges, volumes of gas sold, end of test year plant, uncollectibles, payroll expenses, arbitration case expenses, rate case expense, postretirement benefit costs, and interest synchronization. The Public Staff also adjusted state income taxes to reflect a weighted state surtax rate based on an average of the fiscal years ending September 30, 1994, 1995, and 1996.

In the stipulation, the Company and the Public Staff agreed that the proper level of state income taxes is $103,507. No other party offered any evidence as to the appropriate level of state income taxes.

Federal Income Taxes

The Company offered evidence that the actual level of federal income taxes during the test period was $17,160. The Company proposed pro forma, annualizing, and accounting adjustments of $166,135. The Company contended that these adjustments are necessary to reflect the computation of federal income taxes after the other accounting, annualizing, and pro forma adjustments.

Public Staff witness Grimsley proposed to increase the Company's pro forma federal income taxes by $215,753 to reflect the Public Staff's adjustments to cost of gas, changes in fixed gas costs, volumes of gas sold, end of test year plant, uncollectibles, payroll expenses, arbitration case expenses, rate case expense, postretirement benefit costs, and interest synchronization. This adjustment also includes the adjustment to reduce federal income taxes for the amortization of excess deferred income taxes of $5,750.

The Company offered evidence that the actual level of "amortization of investment tax credits" during the test period was $9,609. The Company did not propose any pro forma adjustments. The Public Staff agreed in its prefiled testimony and exhibits that the appropriate level of "amortization of investment tax credits" is $9,609. No other party offered any evidence on this issue.

In the stipulation, the Company and the Public Staff agreed that the proper level of federal income taxes is $399,047. No other party offered any evidence as to the appropriate level of federal income taxes.

Summary Conclusion

The Commission concludes that the level of state and federal income taxes found reasonable in the stipulation between the Company and the Public Staff is appropriate for use in this case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54

Total pro forma operating revenue deductions under present rates is the sum of various pro forma expenses discussed in Findings of Fact Nos. 33-53. In addition, in the stipulation, the Company and the Public Staff agree that the appropriate pro forma level of total operating revenue deductions under present rates is $16,206,496. No other party offered any evidence on this issue.

The Commission, after considering all of the evidence set forth above, concludes that the unchallenged operating revenue deductions for use in setting rates in this proceeding is shown in the following chart:

Item	Amount
Gas operating revenue	$17,443,093
Operating revenue deductions:	
Cost of gas	11,276,348
Operation and maintenance	3,168,245
Depreciation	516,286
General taxes	743,062
State income taxes	103,507
Federal income taxes	399,048
Total operating revenue deductions	16,206,496
Total operating income for return	$1,236,597

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 55-59

Capital structure and cost of capital were stipulated by the Company and the Public Staff, and no other party challenged those issues. The stipulated ratios and cost rates are:

	Ratio	Cost Rate	Weighted Cost
Common Equity	50.00%	11.90%	5.95%
Debt	50.00%	8.30%	4.15%
Totals	100.00%		10.10%

The Commission concludes that the stipulation is reasonable and proper and should be adopted for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 60

To provide the Company with the opportunity to earn the returns found appropriate in this Order, the Commission finds it necessary to decrease the Company's annual revenues by $377,761. This decrease incorporates an increase in non-gas costs of $315,545 netted with a decrease in fixed gas costs of $693,3D6. The result is an annual revenue requirement of $17,065,332, which will allow the Company a reasonable opportunity to earn the return on common equity that the Commission has found just and reasonable.

The following schedules summarize the gross revenues and rate of return the Company should have a reasonable opportunity to achieve based on the approved decrease. These schedules, illustrating the Company's gross revenue requirements, incorporate the findings and conclusions found reasonable by the Commission.

SCHEDULE I
NORTH CAROLINA GAS SERVICE
Division of PENNSYLVANIA & SOUTHERN GAS COMPANY
DOCKET NO. G-3, SUB 178
STATEMENT OF NET OPERATING INCOME FOR RETURN
For the Test Year Ended December 31, 1992

Item	Present Rates	Approved Decrease	Approved Rates
Gas operating revenue	$17,443,093	$(377,761)	$17,065,332
Operating revenue deductions:			
Cost of gas	11,276,348		11,276,348
Operation and maintenance	3,168,245	(321)	3,167,924
Depreciation	516,286		516,286
General taxes	743,062	(12,164)	730,898
State income taxes	103,5D7	(28,592)	74,915
Federal income taxes	399,048	(114,473)	284,575
Total operating revenue deductions	16,206,496	(155,550)	16,050,946
Net operating income for return	$ 1,236,597	$(222,211)	$ 1,014,386

SCHEDULE II
NORTH CAROLINA GAS SERVICE
Division of PENNSYLVANIA & SOUTHERN GAS COMPANY
DOCKET NO. G-3, SUB 178
STATEMENT OF RATE BASE AND RATE OF RETURN
For the Test Year Ended December 31, 1992

Item	Amount
Gas plant in service	$14,363,151
Accumulated depreciation	(3,999,219)
Net gas plant in service	10,363,932
Gas in storage inventory	520,627
Materials and supplies	235,160
Cash working capital	396,031
Customer deposits	(79,126)
Tax accruals	(218,026)
Pension related cost-free capital	(189,878)
Accumulated deferred income taxes	(985,300)
Rate base	$10,043,420
Rates of return:	
Present rates	12.31%
Approved rates	10.10%

SCHEDULE III
NORTH CAROLINA GAS SERVICE
Division of PENNSYLVANIA & SOUTHERN GAS COMPANY
DOCKET NO. G-3, SUB 178
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the Test Year Ended December 31, 1992

Item	Capitalization Ratio	Rate Base	Embedded Cost Rate	Net Operating Income
		Present Rates		
Long-term debt	50.00%	$ 5,021,710	8.30%	$ 416,802
Common equity	50.00%	5,021,710	16.33%	819,795
Total	100.00%	$10,043,420		$1,236,597
		Approved Rates		
Long-term debt	50.00%	$ 5,021,710	8.30%	$ 416,802
Common equity	50.00%	5,021,710	11.90%	597,584
Total	100.00%	$10,043,420		$1,014,386

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61-62

The evidence supporting these findings is found in the testimony and exhibits of Public Staff witness Davis.

Witness Davis stated that the proposed customer attachment fee of $15.00 was an effort to offset some of the cost of adding new customers while not discouraging growth. The proposed connection fee would be for new residential and small commercial customers, who would be served on Rate Schedules 101 and 102, respectively. Witness Davis testified that the fee would apply to new installations only and not to requests for turn-ons of services already provided at premises or dwellings. The charge should be included in P&S's tariffs and should be explained in its rules and regulations.

Witness Davis testified that the Public Staff estimates that this fee will generate $6,576 in annual revenues. Davis Exhibit D reflects this amount in the proposed revenue level and rate design.

P&S did not oppose the new customer attachment fee and no other party presented testimony on this matter.

The Commission concludes that the uncontested customer attachment fee is an appropriate charge for new residential and commercial customers. The Commission further notes that this charge should apply to new installations and not to seasonal turn-ons, re-establishment of service for non-pay or other reasons, or customers who purchase or rent a premise or dwelling and establish a new service where gas is already available.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 63-81

COST OF SERVICE

The evidence for these findings of fact is contained in the testimony and exhibits of Company witness Carl and Public Staff witnesses Davis and Larsen.

Company witness Carl prepared cost-of-service studies under the end-of-period revenue level and the Company's proposed revenue level. Public Staff witness Larsen also prepared two cost-of-service studies: one under the end-of-period revenue level and the other under the Public Staff's recommended revenue level. As testified to by witness Larsen, the main differences in the studies presented by P&S and the Public Staff relate to the levels of revenue, volumes, plant investment and expenses. There were also some minor differences in the way a few of the allocation factors were generated and utilized.

Both the Company and the Public Staff used the Seaboard cost-of-service model, which allocates fixed gas costs on the basis of 50% to peak demand and 50% to annual sales (average demand). Through cross-examination by CUCA, witness Larsen testified that there are other cost-of-service models, including the Peak Responsibility Method and the United Method. The Peak Responsibility Method assigns 100% of the fixed costs on the basis of peak demand, whereas the United Method assigns 75% of the fixed costs on average demand and 25% on peak demand.

Witness Larsen explained that in preparing the cost-of-service study he attempted "to allocate on the best available allocation we have for that particular item." He also testified that he attempted "to assign directly ones [costs] that we can." and that the cost-of-service study is an "attempt to allocate costs in the way those services were utilized."

CUCA argued in its brief that the Commission must adopt a cost-of-service study in this proceeding in order to adequately consider cost of service in designing rates. Although CUCA argued that the Public Staff's cost-of-service study was flawed, CUCA stated, "While recognizing that Mr. Larsen's cost-of-service study is 'skewed' against industrial customers, the Commission should use it for rate design purposes in this proceeding pending the development of a theoretically sound cost-of-service study in a future general rate case." (CUCA Brief, p.22)

The Commission agrees with witness Larsen's statements that the cost-of-service study is an attempt to allocate costs based on the best available allocations. The Commission notes that there are different cost-of-service models. The Commission concludes that while a cost-of-service study may be accurate with regard to internal calculations, it cannot be relied on with complete certainty in establishing rates or determining rates of return by customer class. Therefore, the Commission does not adopt any one cost-of-service study in this docket and will only take notice of the cost-of-service studies in considering rate design.

RATE DESIGN

Prior to the hearing, the Company and Public Staff met to deliberate on certain issues of the general rate case proceeding. All areas of controversy were settled and the Company agreed with the rate design as proposed by witness Davis.

The rate design in this case must distribute a decrease in rates and charges of $377,761, as detailed in Finding of Fact No. 60.

Witness Davis testified that in evaluating rate design, he had reviewed the cost-of-service studies performed by witness Larsen. He stated that due to the subjective nature of the studies, he did not depend solely on them for rate design. He further testified that while the cost-of-service studies were useful guides, they could not objectively show the returns paid by each customer class. Witness Davis testified that there are other important factors to consider in designing rates. He testified:

> Value of service is an important consideration because it recognizes that the price paid for natural gas service cannot be significantly greater than a satisfactory alternate. That gas is cleaner burning and easier to use also affects its value for some customers. Value of service consideration is the reason why rates are designed to allow negotiations based on alternative fuels and also transportation of gas procured by end-users.
>
> The type of service, quantity of use, time of use and manner of service are considered by reviewing customer characteristics. Different types of customers have different needs. Heat sensitive residential and commercial customers need more security of service during peak winter days and contribute more margin to pay for storage services than do non-heat sensitive customers. There are also distinctions among industrial customers, such as those

> requiring a more firm supply than others. Other industrial customers use their gas for boiler fuel. Some may decide not to have an alternative fuel. Rate design should reflect differences among customers.
>
> Rates should be attractive to new customers. Industrial customers are energy intensive and are very conscious of their choice of fuels. Residential customers are also concerned with their long-term commitment to their energy choice. Rates to all customers should be set in a manner to be appealing to all classes of customers to contribute both to the health of the utility and the welfare of its customers.
>
> Historical rate design is considered both to evaluate the results of past rate design and to anticipate the response to proposed rate design. For example, in past cases for the Company (Docket Nos. G-3, Sub 141 and G-3, Sub 167), residential rates were increased 12.8% and 10.01% respectively. Industrial rates were reduced by 2% to 4.4% and by 2.9% and 7.28%. This was an effort to realign rates at that time. Considering what has occurred in the past, I believe the trend should continue in this case, but not by the same magnitude. In this case, as shown on Davis Exhibit E, the Public Staff is recommending a .70% decrease in residential revenues and a decrease in industrial revenue of 3.83%.
>
> In reviewing the revenue stability of the utility, I considered whether the rates would enable the Company to attract new customers and keep the customers it has. Dramatic changes in rate design can result in unpredictable revenue shifts and should generally be avoided.
>
> Last, there are economic and political factors to consider. Economic growth may be encouraged through rate design in the Company's service territory. The North Carolina Legislature has adopted laws that are a means to encourage natural gas expansion. Proper rate design can facilitate such expansion.

He also stated that his approach to designing rates is consistent with that followed in prior cases, including Docket No. G-3, Subs 141 and 145, in which the North Carolina Supreme Court affirmed the Commission's findings that the Public Staff's rate design was appropriate. State ex rel. Utilities Commission v. Carolina Utility Customers Association, 328 N.C. 37 (1991).

During cross-examination by CUCA's attorney, witness Davis testified that "cost-of-service studies are subjective and judgmental at best" and that he did not depend on them solely in designing rates. He also testified that cost-of-service studies are "useful as a guide but, like other cost studies, cannot objectively show the returns paid by each customer class." Witness Davis also testified that industrial customers are required in most cases to have an alternate fuel source installed. Therefore industrial customers are a higher risk form of customer in that not only can they negotiate their rates with the Company, they may leave the system entirely should economic factors dictate.

Residential and commercial customers, on the other hand, are not required to install an alternative form of energy. Witness Davis stated that usually residential customers would not invest the money necessary to install alternative energy, and once their choice has been made it is usually a long-term commitment with no options.

During cross-examination by CUCA, Company witness Carl testified that the industrial negotiations benefit all customer classes. The industrial customers receive a lower price. Other customers who are principally residential and commercial customers benefit by having the industrial customers stay on the system and continue to make some contribution to fixed costs.

Witness Davis further testified that because rate design is an assimilation of numerous factors, isolation of a single factor would not be prudent rate design. He testified that alternate fuels utilized for rate design alone would be in error because the prices of fuel oils and propane for industrials vary frequently.

The Commission is of the opinion that the cost-of-service studies presented by the Public Staff are certainly an important and relevant guide or factor to be weighed in designing rates in this preceding. The studies presented show varying rates of return depending on the methodology followed and the assumptions involved. There are several other factors or ratemaking principles in addition to cost of service to consider in designing rates for natural gas utilities, as has been discussed at length by the Commission in other general rate case orders. Among these are: (1) the value of service to the customer; (2) the type and priority of service received by the customer and, if the service is interruptible, the frequency of interruptions; (3) the quantity of use; (4) the time of use; (5) the manner of service; (6) the competitive conditions in the market place related to the acquisition of new customers; (7) the historic rate differentials between the various classes of customers; (8) the revenue stability to the utility; and (9) the economic and political factors which are inherent in the ratemaking process.

Rates of return for customers who have no alternate fuels readily available, such as residential customers, should not be the same as rates of return for those customers who do in fact have alternate fuels, such as boiler fuel customers. Rates of return for customers who cannot negotiate their rates with the Company or who cannot obtain supplies of cheaper gas under transportation rates should not be the same as rates of return for those customers who can and indeed do negotiate their rates. The services provided in either case are not directly comparable, so the respective rates of return should not be identical either. The risk to the Company of maintaining its margin on service to the high-priority market, which includes residential customers, is significantly less than the risk to the Company of maintaining its margins on service to large industrial customers. This risk is further magnified when one looks at the Company's customer sales mix, which consists of 23.80% residential, 15.23% commercial, 14.71% firm industrial, and 46.26% interruptible industrial.

The stipulation between P&S and the Public Staff accepts the rates proposed by the Public Staff. As testified to by witness Davis, the cost-of-service study shown in Larsen Exhibit B, entitled "Public Staff's Recommended Revenue Level" was prepared by witness Larsen using revenues by customer class based on the rates designed by witness Davis. That cost-of-service study yields rates of return by customer class of -.31% for Rate 101 (Residential), 11.93% for Rate 102 (Small General), 14.88% for Rate 104 (Large General) and 39.12% for Rate 105 (Interruptible). As shown on Davis Exhibit E, the Public Staff's proposed revenues produced a .70% decrease in revenues from the residential class compared to end-of-period revenues.

In light of the negative residential rate of return reflected in Larsen Exhibit B, the Commission cannot justify or approve a reduction in residential rates in this case as proposed by the Public Staff with the concurrence of P&S. While the Commission has repeatedly affirmed that rates must be set considering a number of factors, including estimated cost-of-service studies and the rates of return they yield, for the reason's stated above, it would not be reasonable in this case to approve a rate reduction for residential customers resulting in the negative rate of return for residential customers shown in Larsen Exhibit B. For that reason, the Commission concludes the rate design agreed to by the Company and the Public Staff is unreasonable and should be modified as set forth below.

The Commission notes that, according to Davis Exhibit E, the stipulation calls for an overall revenue decrease of 2.17%. As was stated previously, witness Davis testified that, in the Company's last two general rate cases (G-3, Sub 141 and G-3, Sub 167), residential customers have seen rate increases of 12.8% and 10.01%, respectively, while various industrial classes have received rate reductions of 2% to 4.4% and 2.9% and 7.28%. The industrial rates proposed by P&S and the Public Staff in this case have all been decreased for the various industrial rate schedules, ranging from a decrease of 3.09% to a decrease of 3.83%, while the commercial rates have been decreased .92% and proposed residential rates have been decreased .70%. Considering the historical changes as well as other factors, including the fact that this proceeding involves an overall revenue <u>decrease</u> rather than a revenue increase for P&S, the Commission cannot find justification for either reducing or increasing residential rates in this case. The Commission therefore concludes that it would be just and reasonable to set rates so that the revenue collected from the residential class as shown in column (B) of Davis Exhibit E remains unchanged. Furthermore, the Company should reallocate the decrease in residential revenue shown in column (D) of Davis Exhibit E to other rate classes proportionally using the total rate base shown on line 32 of Larsen Exhibit B as a weighting factor. In light of the changes to the stipulated rates, the Commission concludes that it would be just and reasonable to leave the facilities charge for Rate Schedule 101 undisturbed at $6.00 per month. No change was proposed in the facilities charges of other rate schedules.

The Commission finds that the rate design approved in this proceeding does not unreasonably discriminate against the industrial customers, after weighing and balancing all of the relevant factors, and that such rate design is just and reasonable.

<u>SERVICE CHARGES</u>

The Company through witness Carl also proposed to increase its charges for certain categories of service work. The miscellaneous service charges are for reconnections, bad check fees, resetting meters, rereading meters, and repairing electrical and/or plumbing problems. He testified that the increase in revenues from the miscellaneous service charges would be reflected in an adjustment made to credit operating and maintenance expense by $27,236.

The Commission finds that this issue was uncontested and is of the opinion that the proposed miscellaneous service charges are consistent with the other gas utilities fees. Therefore, the Commission finds these miscellaneous service charges appropriate for this proceeding as set forth in Appendix A.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 82-83

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Davis and Larsen.

The Commission notes that, although the cost-of-service study is subjective, the Purchased Gas Expense Exhibit sponsored by witness Larsen has known volumes and dollar figures and is allocated as accurately as possible. The Commission concludes that although the purchase gas expense allocations may not be exact, they are accurate and are the best available tool for calculating the fixed gas cost recovery rates. Therefore, the Commission adopts the fixed gas cost recovery rates recommended by the Public Staff, which are as follows: Rate 101: $1.1097/dt; Rate 102: $0.9483/dt; Rate 104: $0.5036/dt; and Rate 105: $0.2972/dt.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 84-88

The evidence for these findings is contained in the testimony and evidence of Company witness Carl and Public Staff witness Davis.

In this proceeding, the Company has proposed Rate Schedule No. 106, under which transportation service is available for any customer connected to the Company's system who has obtained an independent supply of natural gas, who has arranged to have this supply delivered to one of the Company's existing delivery points, and who qualifies for the purchase of gas under Rate Schedule No. 104 or 105. Under proposed Rate Schedule No. 106, the Company is required to attempt to deliver gas previously transported to the Company by connecting pipelines for the customer's account in accordance with a service agreement between the Company and the customer. However, the Company reserves the right to suspend transportation service on any day when, in the Company's sole opinion, its operating conditions are such that suspension of service is necessary. Under the Company's proposed transportation schedule, the rate to be charged for gas service may vary but may not exceed the maximum of certain charges specified in the rate schedule.

Existing Rate Schedule 106 is a full margin transportation rate. Under Rate Schedule No. 106, the transportation of customer-owned gas is priced at the applicable sales rate less the commodity cost of gas, relevant gross receipt taxes, and any temporary increments or decrements. Both witness Carl and witness Davis testified that they favored the continuation of full margin transportation rates.

In other proceedings, the Commission has approved full margin transportation rates for several reasons. These reasons include that the use of a less than full margin transportation rate would require sales rate customers to subsidize transportation customers, that the services provided by local distribution companies to transportation customers and sales rate customers are identical, that sales rate and transportation gas pass through the local distribution company's delivery system in the same manner, that local distribution companies perform the same billing services for both sales rate and transportation customers, that customers use sales rate and transportation gas for the same purposes, that the consumption characteristics of sales rate and transportation customers are similar, and that the Company is required to obtain a gas supply for transportation customers. The Supreme Court has affirmed Commission decisions approving full margin transportation rates.

The Commission concludes that the proposed full margin transportation rates are appropriate for use in this proceeding, consistent with the Commission's philosophy and recent past decisions involving Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, Inc., and North Carolina Natural Gas Corporation. A full margin rate is defined as the regular sales rate at which the customer would normally purchase gas less gross receipts tax, less any temporary increments or decrements, less the benchmark cost of gas. This residual rate is then increased to include gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 89-94

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Carl and Public Staff witness Davis.

Witness Carl testified that the Weather Normalization Adjustment (WNA) mechanism would allow the Company to recover non-gas costs in the same manner in which the costs were designed in rates. He further testified that there would be no over-recovery in colder than normal periods and no under-recovery in warmer than normal periods for heat sensitive customers. He also stated that the WNA would also provide a more stable level of income and a better matching of costs and revenues.

Witness Davis supported the WNA mechanism for the Company's customers who would be served under Rate Schedule Nos. 101 and 102. He testified that the WNA would allow the Company to collect on a more stable basis non-gas costs associated with its heat sensitive customers and would reduce some of the uncertainty in the Company's earnings due to fluctuations in temperature.

Witness Davis made two recommendations regarding the WNA implementation. First, he recommended that the R_i values as determined on Davis Exhibit F should be utilized in the WNA calculation for the applicable rate schedules. Second, he recommended that the Public Staff's heating degree day (HDD) data base be used for the calculation of the WNA. He testified that the National Oceanic and Atmospheric Administration (NOAA) truncates its data instead of rounding. Therefore errors would occur in the WNA formula if NOAA data were used.

Witness Davis testified during cross-examination that there may be a few customers served under Rate Schedule No. 102 that may not be heat sensitive. He stated that after a period of experience with the WNA, customer characteristics may be reviewed to determine if exclusion from the WNA may be appropriate.

The Commission concludes that P&S's WNA should operate in the same manner as the WNA clauses recently approved for Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, Inc., and North Carolina Natural Gas Corporation, except that the Public Staff's HDD data base should be used.

The Commission concludes that the WNA as proposed by P&S and amended by the recommendations of the Public Staff and adjusted by ordering paragraph 7 of this Order is appropriate for implementation in this rate case. The Commission further concludes that monthly accounting of the functioning of the mechanism be filed with the Commission and Public Staff during the period when the WNA is in effect. The format for this accounting shall be in the same manner as filed by the other LDCs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 95

The evidence in support of this finding of fact is contained in the testimony and exhibits of Company witness Carl, Public Staff witness Davis, and in an amendment of the Company's proposed service rules and regulations filed September 16, 1993.

The Company and the Public Staff agreed on revised language to the Company's service rules and regulations prior to the hearing. The Company's amended filing of the service rules and regulations on September 16, 1993, reflects the revisions of the Public Staff.

No other party presented testimony on the Company service rules and regulations.

The Commission finds that P&S's service rules and regulations as agreed upon by the Public Staff and amended by filing on September 16, 1993, are just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 98-102

The evidence for these findings of fact is contained in the testimony of P&S witness Carl and Public Staff witnesses Davis and Grimsley.

North Carolina General Statute 62-33.4 requires that P&S submit to the Commission information and data for a historical twelve-month test period. This information and data should include P&S's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes and transportation volumes. In addition to this information, Commission Rule R1-17(k)(6)(c) requires that weather-normalized sales volume data, workpapers, and direct testimony and exhibits supporting the information be filed.

Witness Carl testified that P&S complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) and no witness contradicted his testimony. Witness Carl also testified that P&S filed with the Commission and submitted to the Public Staff throughout the review period complete monthly accountings of the computations required by Commission Rule R1-17(k)(5)(c). Public Staff witness Grimsley confirmed that the Public Staff had reviewed the filings and that they complied with the Rules.

The Commission concludes that P&S has complied with all the procedural requirements of N.C.G.S. 62-133.4(c) and Commission Rule R1-17(k) for the twelve-month review period ended April 30, 1993.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 98-102

The evidence supporting these findings of fact is found in the testimony of P&S witness Carl and Public Staff witnesses Grimsley and Davis.

Witness Carl testified that during the twelve-months ended April 30, 1993, P&S incurred fixed gas costs of $2,124,803 and collected $2,565,435 in revenues attributed to those costs. He also testified that commodity costs incurred were $8,286,483 and exceeded amounts collected for commodity gas by $98,444. Witness Carl stated that P&S also experienced negotiated sales under-collections of $89,663 and returned $2,017,249 through temporary decrements to sales customers. He further testified that the balance in the all customers deferred gas cost account was $565,154 excluding gross receipts tax and that the balance in the sales only deferred gas costs account was $213,546 excluding gross receipts tax, at April 30, 1993.

Witness Grimsley testified that the Public Staff had examined P&S's accounting for gas costs during the test year and determined that P&S had properly accounted for its gas cost.

Witness Carl also testified that P&S's contractual arrangements and the resulting gas cost were prudent. He testified that all of the Company's contracts were tied to a spot market index and that this practice was both consistent with the purchasing strategies of other gas utilities and fairly represents the market value of natural gas. He further testified that the Company's high load factor of 91% reflects the success in P&S's purchasing strategy by lowering fixed costs.

Witness Davis testified that the Public Staff reviewed all of the data filed with the Commission and the information received from the Company by data requests and determined that the Company's gas costs during the review period were prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 103-105

The evidence for these findings is found in the testimony of Public Staff witness Davis. Witness Davis stated that the balances in the deferred accounts at the twelve months ended April 30, 1993, should be returned to customers by temporary decrements.

Witness Davis therefore recommended placing a temporary decrement of $.1649/dt in the rates of all sales and transportation customers to refund $583,957, including gross receipts tax, relating to the balance in the all customers deferred account. Further, he stated that a temporary decrement of $.0623/dt should be placed in the rates of all sales customers to refund $220,650, including gross receipts tax, relating to the balance in the sales only deferred account. He recommended that these temporary decrements replace any existing decrements already in rates. No other party offered evidence on this matter.

The Commission concludes that P&S has properly accounted for all gas costs and that the Company's purchasing strategies and procurement of gas supply and capacity is prudent.

IT IS, THEREFORE, ORDERED as follows:

1. That Pennsylvania and Southern Gas Company, North Carolina Gas Service Division is authorized to adjust its rates and charges to decrease its annual gross revenues by $377,761, effective for service rendered on and after the date of this Order.

2. That Pennsylvania and Southern Gas Company, North Carolina Gas Service Division's accounting for gas costs during the twelve month period of review be, and the same hereby is, approved.

3. That the gas costs incurred by Pennsylvania and Southern Gas Company, North Carolina Gas Service Division during the twelve month period of review were reasonable and prudently incurred and the Company be, and hereby is, authorized to recover its gas costs as provided herein.

4. That Pennsylvania and Southern Gas Company, North Carolina Gas Service Division shall arrange to place a temporary decrement of $.1649/dt in the rates of all sales and transportation customers and a temporary decrement of $.0623/dt in the rates of all sales customers.

5. That the Weather Normalization Adjustment (WNA) mechanism is approved and shall be effective for service rendered on and after the date of this Order.

6. That the changes to the Company's Service Rules and Regulations discussed in this Order are approved and shall be effective for service rendered on and after the date of this Order.

7. That P&S is required to file tariff sheets not later than ten (10) days from the date of this Order reflecting the rates to achieve the decrease approved in Ordering Paragraph No. 1. Such rates shall be designed in accordance with the rate design guidelines set forth in Findings of Fact Nos. 78-80.

8. That P&S is required to notify its customers of the approved rates by appropriate notice in the next billing cycles following the date of this Order. The Notice to Customers shall be submitted to the Commission within ten (10) days of the date of this Order for approval prior to issuance.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

COMMISSION APPROVED MISCELLANEOUS CHARGES FOR PENNSYLVANIA & SOUTHERN GAS COMPANY NORTH CAROLINA GAS SERVICE DIVISION

DOCKET NO. G-3, SUB 178

	DESCRIPTION	APPROVED CHARGES
1.	Turn-on During Working Hours For April 1 Through August 31 (New Customers Exempt)	$25.00
2.	Turn-on During Working Hours For September 1 Through March 31 (New Customers Exempt)	$40.00
3.	New Customer Attachment Fee (Applies Only To Residential And Commercial Customers Who Require A New Service Line Installation)	$15.00
4.	Turn-On For Non-pay Year Around	$40.00
5.	Turn-on After Working Hours	$57.50
6.	Meter Reset For Non-pay During Working Hours	$41.00
7.	Meter Reset For Non-pay After Working Hours	$57.50
8.	Light Water Heater After Hours	$28.75
9.	Bad Check Fee	$15.00
10.	Pick Up Key For Service Work	$10.25
11.	Reread Meter	$10.25
12.	Electrical Or Plumbing Problem	$10.25

DOCKET NO. G-5, SUB 279

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Public Service Company of North Carolina, Inc. - Recovery of Costs Associated with Additional Pipeline Capacity	)))	ORDER REQUIRING REFUNDS

BY THE COMMISSION: By Order of May 14, 1990, the FERC issued Transco a certificate of public convenience and necessity for its Southern Expansion Project and approved rates. The project provides additional natural gas pipeline capacity during winter months. Piedmont, NCNG, and Public Service subscribed to the new service, beginning November 1, 1990.

Piedmont and NCNG filed applications with the Commission under G.S. 62-133(f) seeking authority to increase rates in order to recover the new Southern Expansion costs. The Commission allowed these rate increases, and appeals were taken on the issue of whether the statute, as then worded, was applicable to the cost of additional pipeline capacity such as Southern Expansion.

Public Service, by letter dated December 11, 1990, advised the Commission that it would recover its Southern Expansion costs through its Rider D mechanism. On January 18, 1991, the Public Staff filed a Petition in this docket arguing that the Rider D mechanism was never intended to allow recovery of the costs of additional pipeline capacity such as Southern Expansion and asking that Public Service be required to cease and desist, to refund costs already collected, and to seek specific Commission authority for the recovery of the Southern Expansion costs. Public Service filed a Response on February 13, 1991, and an oral argument was subsequently held.

The Commission issued an Order on April 5, 1991. The Commission, after enumerating and endeavoring to balance several difficult considerations, concluded that the past recovery of Southern Expansion costs by Public Service through Rider D should not be disturbed. However, the Commission required Public Service to file new tariffs so as to recover future Southern Expansion costs <u>other than through Rider D.</u> Such recovery was made provisional, and the Commission ordered that the monies collected be placed in a deferred account "to be disposed of by Order of the Commission following decision of the appellate courts" in the appeals relating to the recovery of Southern Expansion costs by Piedmont and NCNG.

Public Service collected its Southern Expansion costs pursuant to the provisions of the April 5, 1991, Order from April 1991 through October 1991. Public Service had a general rate case decision in November 1991 in which the Southern Expansion costs were incorporated into rates.

The Court of Appeals decided the Piedmont and NCNG appeals in 1992. The Court reversed Commission Orders allowing recovery of Southern Expansion costs pursuant to the provisions of G.S. 62-133(f), as the statute then read. <u>State ex rel. Utilities Commission</u> v. <u>Carolina Utility Customers Assn.,</u> 106 N.C. App. 218, 415 S.E.2d 758 (1992); <u>State ex rel. Utilities Commission</u> v. <u>Carolina</u>

Utility Customers Assn., 106 N.C. App. 306, 416 S.E.2d 199 (1992); State ex rel. Utilities Commission v. Carolina Utility Customers Assn., 106 N.C. App. 491, 417 S.E.2d 75 (1992). The Supreme Court denied review.

On April 28, 1993, the Commission issued an Order approving a refund plan for NCNG in Docket No. G-21, Sub 289. The Commission has scheduled proceedings to establish a refund plan for Piedmont by a recent Order in Docket No. G-9, Subs 300, 306, and 308. We must now consider Public Service.

On April 29, 1993, the Public Staff filed a Motion for Order Requiring Refunds in this docket asking that, in light of the appellate decisions, Public Service be required to refund the Southern Expansion costs in the deferred account pursuant to the April 5, 1991, Order.

Public Service filed a Response on May 18, 1993, in which it argued that the appellate decisions do not apply to it because, unlike Piedmont and NCNG, it never sought recovery of Southern Expansion costs pursuant to G.S. 62-133(f). Public Service went on to argue that the Southern Expansion costs were properly recoverable through Rider D and that it should be allowed to keep the money in the deferred account. "To the extent that reconsideration of the April 1991 Order may be deemed necessary to accomplish that result, [Public Service] hereby requests the Commission to do so." Alternatively, Public Service argued that if it is not allowed to recover its full Southern Expansion costs through Rider D, the corresponding gas cost savings which were flowed through Rider D should be returned to the Company.

The Public Staff filed a Reply on June 9, 1993, in which it requested an evidentiary hearing. Public Service filed a response on June 22, 1993, in which it argued that neither a hearing nor an oral argument is needed.

The Commission has carefully considered all prior proceedings in this docket, as well as the recent filings summarized above, and the Commission concludes that neither hearing, argument, nor written briefs are needed. The Commission finds that the language and intent of the April 5, 1991, Order is controlling, and the Commission finds no good cause to reconsider that Order.

The recovery of Southern Expansion costs by Piedmont, NCNG, and Public Service presented difficult legal and equitable issues. These were complicated by the rate structure of Southern Expansion and by the different methods of recovery proposed by the three utilities. By the time of the April 5, 1991 Order in this docket, the Commission had determined that, as near as possible, the three companies should be treated consistently in the future. To achieve that, the Commission required Public Service to file tariffs to recover its Southern Expansion costs other than through Rider D, and the Commission ordered that this recovery be provisional, that the recovery be placed into a deferred account and that the deferred account be disposed of following decision of the Piedmont and NCNG appeals. (This was consistent with what we ordered for NCNG dependent upon the outcome of the Piedmont appeal.) The appeals have now been decided, and refunds either have been or will be required of both NCNG and Piedmont. The appellate decisions are relevant for present purposes because the Commission specifically allowed Public Service to recover its Southern Expansion costs dependent upon the outcome of the appeals.

Public Service still argues, as it did back in 1991, that its Southern Expansion costs were properly recoverable through Rider D, but the Commission ordered Public Service to recover these costs <u>other than through Rider D</u> by our April 5, 1991, Order. Public Service asks us to reconsider that Order, but we decline to do so. That Order reflected a difficult balance, and Public Service received considerable benefit from that Order since it was allowed to keep the Southern Expansion costs previously recovered without any requirement that that recovery be dependent upon the appeals. We will not disturb that decision now.

Public Service states that it was able, beginning in November 1990, to secure gas at a lower cost and on a more reliable basis via Southern Expansion and the commodity savings associated with gas moved under Southern Expansion were included in Rider D. These savings served to offset negotiated margin losses and contributed to customer refunds under Rider D. Accordingly, Public Service argues if the Commission does not allow its full Southern Expansion costs to be recovered under Rider D, then in fairness the corresponding gas cost savings should be removed from Rider D and retained by the Company. The Commission disagrees. Rider D provides for variations between Public Service's commodity gas costs and its base cost of gas and for the use of gas cost savings to offset negotiated sales losses with the remainder being refunded to customers. The Commission notes the distinction between commodity gas costs and the costs of additional capacity such as Southern Expansion. The Commission is not persuaded that a correlation exists which would warrant such treatment as Public Service is proposing. Such treatment would be contrary to the express terms of Rider D. Accordingly, the Commission will deny the retention by Public Service of any commodity cost savings associated with Southern Expansion.

The Commission therefore concludes that Public Service shall be required to refund to customers the Southern Expansion costs in the deferred account set up pursuant to the April 5, 1991, Order. Public Service shall propose a refund plan which will be subject to comment by other parties. The Commission urges Public Service to consult with other parties in formulating its proposed plan.

IT IS, THEREFORE, ORDERED as follows:

1. That Public Service should be, and hereby is, required to refund to its customers the Southern Expansion costs recovered on a provisional basis and held in a deferred account pursuant to the Commission's April 5, 1991, Order in this docket, and

2. That Public Service shall file and serve a refund plan designed to effect this decision on or before August 16, 1993, and other parties shall have until August 26, 1993, within which to comment.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of July 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. G-5, SUB 300

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by Public Service Company of North Carolina to Authorize Establishment of a Natural Gas Expansion Fund Pursuant to G.S. 62-158	)	ORDER ESTABLISHING EXPANSION FUND AND APPROVING INITIAL FUNDING

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, August 25, 1992, at 10:00 a.m. and Tuesday, March 9, 1993, at 9:30 a.m.

BEFORE: Chairman William W. Redman, Jr., and Commissioner Julius A. Wright, Presiding; Commissioners Sarah Lindsay Tate, Robert O. Wells, Laurence A. Cobb, Charles H. Hughes, and Allyson K. Duncan

APPEARANCES:

For Public Service Company of North Carolina:

Wade H. Hargrove and William A. Davis, II, Tharrington, Smith & Hargrove, Post Office Box 1151, Raleigh, North Carolina 27602-1151

For the Using and Consuming Public:

Gisele L. Rankin, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

Karen E. Long, Assistant Attorney General, and Margaret Force, Associate Attorney General, Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utilities Customers Association, Inc.:

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, Post Office Drawer 1269, Morganton, North Carolina 28655

For McDowell County:

Robert C. Hunter, Hunter & Evans, Post Office Box 1330, Marion, North Carolina 28752

BY THE COMMISSION: On July 8, 1991, the General Assembly of North Carolina enacted G.S. 62-158, which authorizes the Utilities Commission to order that a natural gas utility create a special natural gas expansion fund to be used by that company to construct natural gas facilities in areas of its franchised territory that otherwise would not be feasible. It further enacted G.S. 62-2(9), which declared it to be the policy of the State to facilitate the construction of facilities in and the extension of natural gas service to unserved areas in order to promote the public welfare throughout the State.

General Statute 62-158(d) provided for the Commission to implement the statute by adopting rules for the establishment of expansion funds, for the use of such funds, for the remittance to the expansion fund or to customers of supplier and transporter refunds and expansion surcharges or other funds that were sources of the expansion fund, and for appropriate accounting reporting and ratemaking treatment. By Order dated April 9, 1992, the Commission adopted Rules R6-81 through R6-88 for those purposes.

On May 13, 1992, North Carolina Natural Gas Corporation (NCNG) filed a Petition for establishment of the first expansion fund. The Commission subsequently issued an Order on February 8, 1993, in Docket No. G-21, Subs 306 and 307, establishing an expansion fund for NCNG. That Order is presently on appeal.

On May 22, 1992, Public Service Company of North Carolina (Public Service) filed a Petition seeking the establishment of an expansion fund pursuant to G.S. 62-158 and approval of the deposit of certain supplier refunds.

By Order dated June 10, 1992, the Commission scheduled the matter for public hearing on August 25, 1992, and required Public Service to give public notice of the hearing by inserts in its customers' bills and by publication in newspapers having general circulation in its franchised territory.

Petitions to intervene were made and allowed for Carolina Utility Customers Association, Inc. (CUCA) and McDowell County. The Public Staff and the Attorney General also intervened.

On August 20, 1992, CUCA filed a Motion to Dismiss Public Service's petition on the grounds that G.S. 62-158 is unconstitutional.

The hearing was held as scheduled on August 25, 1992. The following public witnesses appeared and testified: Church Abernathy, County Manager of McDowell County; Dean Buff, McDowell County Commissioner; Jack Harmon, Executive Director of the McDowell Committee of 100; Rod Birdsong, Executive Director of the McDowell County Chamber of Commerce; Earl Daniels, City Manager of Marion; Bill Edwards, Haywood County Commissioner; Patsy Bumgarner, President of the Chamber of Commerce and Executive Director of Economic Development in Alexander County; and Timothy Glass, Chairman of the Alexander County Board of Commissioners. Public Service offered the testimony and exhibit of C. Marshall Dickey, Executive Vice-President of Administration and Marketing. CUCA moved to strike portions of Mr. Dickey's testimony, and the Commission took the motion under advisement.

By Order dated September 2, 1992, the Commission invited all interested persons to file amicus curiae briefs in this docket addressing the issues raised by the motion to dismiss filed by CUCA. Amicus curiae briefs were subsequently filed by Alcoa and Piedmont Natural Gas Company, Inc.

On September 11, 1992, Public Service filed a Supplemental Request for Approval of Funding requesting that additional supplier refunds be included in any expansion fund established by the Commission.

By motion filed September 22, 1992, CUCA requested that the Commission reopen the hearing to consider Public Service's supplemental request and hold a further evidentiary hearing. The Attorney General joined CUCA's motion. The Public Staff, by motion filed September 29, 1992, stated its objection to the inclusion of the supplemental request in this proceeding and requested an extension of time. In response to these filings, the Commission issued an Order on October 1, 1992, indefinitely suspending the filing of proposed orders and briefs and calling for comments from the parties as to how the Commission should proceed.

Also, on October 1, 1992, Public Service filed an analysis conducted by Deloitte & Touche of the feasibility of extending service through Alexander, Franklin, Haywood, McDowell, and Warren Counties (the Deloitte & Touche study) in Docket No. G-5, Sub 290.

Three parties filed comments on October 9, 1992. The Public Staff filed comments to the effect that reopening the hearing for purposes of receiving evidence related to the Deloitte & Touche study would give the Commission the most complete record on which to render its decision in this matter. CUCA reiterated its arguments in favor of reopening the hearing. Public Service filed comments in which it argued that the existing record is adequate to support the creation of an expansion fund and initial funding.

The Commission, by Order dated October 30, 1992, reopened the hearing, scheduled a further hearing for March 9, 1993, required prefiled testimony and required Public Service to publish public notice and provide notice to each of its customers. The hearing was reopened for two purposes: (1) to receive evidence on the Deloitte & Touche study insofar as it relates to whether an expansion fund should be created and whether funding of the general magnitude proposed should be approved and (2) to consider the supplemental request for approval of additional funding.

The reopened hearing was held as scheduled on March 9, 1993. The following public witnesses testified: Daniel G. Horvitz, who testified against the creation of an expansion fund, and Rick Webb, who appeared in support of an expansion fund on behalf of the North Carolina Rural Economic Development Center. Public Service presented the supplemental testimony of C. Marshall Dickey. The Public Staff presented the testimony of George T. Sessoms, Jr., a Public Utilities Financial Analyst and Director of the Economic Research Division of the Public Staff, and the testimony and exhibit of James G. Hoard, Supervisor of the Natural Gas Section of the Accounting Division of the Public Staff.

On March 9, 1993, CUCA filed a Motion to Defer Ruling requesting the Commission to defer entry of a final order until completion of its appeal in the NCNG expansion fund case, Docket No. G-21, Subs 306 and 307. Responses opposing the motion were filed by the Company, by McDowell County and by the Public Staff. On April 13, 1992, the Commission denied CUCA's Motion to Defer Ruling.

Based on Public Service's petition, the testimony and exhibits offered at the hearings, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Public Service is duly organized as a corporation under the laws of this State and is duly authorized to do business in the State. Its principal office and place of business is in Gastonia, North Carolina.

2. Public Service is a public utility engaged in the business of operating natural gas transmission lines, distribution facilities and other facilities for the furnishing and delivering of natural gas service to the public in its franchised territory in central and western North Carolina, pursuant to a Certificate of Public Convenience and Necessity granted by this Commission.

3. The Commission has no authority to rule on CUCA's motion to dismiss the Petition in this proceeding on grounds that G.S. 62-158 is unconstitutional under various provisions of the state and federal constitutions.

4. CUCA's motion to strike portions of the prefiled testimony of C. Marshall Dickey should be, and hereby is, denied.

5. In its petition to authorize establishment of expansion fund and supplemental request for approval of funding, Public Service has complied with the procedural requirements of G.S. 62-158 and Commission Rule R6-82.

6. Public Service has unserved areas within its franchised territory within the meaning of G.S. 62-158 and Commission Rule R6-81(b)(5). These areas include three entire counties: Alexander, McDowell and Warren. In addition, the Company provides only limited service to Franklin and Haywood Counties, and they are virtually unserved.

7. Expansion of natural gas facilities to the unserved areas within Public Service's franchised territory is economically infeasible using traditional financing methods.

8. The General Assembly has made the policy decision that it is necessary and in the public interest to authorize special funding methods, including the use of supplier refunds and customer surcharges, to facilitate the construction of facilities and the extension of natural gas service into areas of the State where it may not be economically feasible to expand with traditional funding methods in order to provide infrastructure to aid industrial recruitment and economic development.

9. The establishment of an expansion fund for Public Service for the purpose of constructing transmission lines into unserved counties in its territory that are otherwise infeasible to serve in order to provide infrastructure to aid industrial recruitment and economic development is consistent with G.S. 62-158 and 62-2(9) and is in the public interest.

10. Expansion of natural gas facilities in the unserved areas by use of expansion funds can reasonably be expected to assist in the economic development of unserved areas in Public Service's franchised territory. The availability of natural gas service is an important factor in industrial recruitment. Economic development will in turn provide a larger tax base, more employment opportunities, and a better quality of life.

11. Customers on Public Service's system stand to benefit from the expansion to be made possible by the expansion fund. These benefits include increased throughput, which tends to reduce expenses per unit of gas sold.

12. G.S. 62-158(b) provides that funding for an expansion fund may include refunds to a local distribution company such as Public Service from the company's suppliers of natural gas and transportation services. The Commission's practice has been to order natural gas public utilities to return such supplier refunds to customers pursuant to G.S. 62-136(c), and the Commission would have done so here but for G.S. 62-158.

13. Public Service originally requested that a supplier refund of $5,815,870, plus applicable interest, which is contingent upon the resolution of an appeal by its interstate pipeline supplier Transco, be approved for deposit into the expansion fund. In addition, Public Service requested that additional supplier refunds of $214,900, plus approximately $21,000 per month that will continue to be received through July 1994 in connection with FERC Docket Nos. RP 88-68, et al., IN 89-1-000, and IN 89-1-001 be approved for deposit.

14. By the Supplemental Request filed September 11, 1992, Public Service requested that two additional supplier refunds received subsequent to the filing of its petition be approved for deposit into the expansion fund. These refunds were (1) a Transco refund in the amount of $4,288,946 received August 7, 1992, and (2) a payment of $51,526, received July 6, 1992, as a result of a Producer Settlement Payment charges true-up.

15. By the time of the March 1993 hearing, Public Service had withdrawn its request to deposit the contingent Transco refund and stipulated to the amount of supplier refunds that the Public Staff had determined to be eligible and appropriate for deposit into an expansion fund.

16. Supplier refunds in the amount of $4,774,840 as calculated in Hoard Exhibit I, plus the additional monthly supplier refunds of approximately $21,000 each through July 1991, plus interest, are authorized sources of funding under G.S. 62-158 and are just and reasonable sources of initial funding for Public Service's expansion fund and should be transferred to the fund.

17. General Statute 62-48 provides for the Commission's Washington, D.C. counsel and related travel expenses of the Commission Staff and the Public Staff to be paid for out of supplier refunds. The statute also provides for the Commission to establish procedures for the natural gas public utilities to set aside reasonable amounts of supplier refunds for these purposes.

18. Generic procedures to deal with setting aside reasonable amounts of supplier refunds for purposes of G.S. 62-48 have been established by separate order dated February 23, 1993, in Docket No. G-100, Sub 57.

19. The balance in Public Service's account for paying the Commission's Washington, D.C. legal counsel and related travel costs, Account 253.03, was $49,220 at January 31, 1993. This balance is adequate at this time.

20. Public Service shall give appropriate notice of the establishment of its expansion fund and approval of initial funding by bill insert.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings of fact is contained in Public Service's petition and the Commission's records and is essentially informational and uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The Commission in the NCNG expansion fund proceeding, Docket No. G-21, Subs 306 and 307, recently ruled that the Commission does not have authority to pass upon the constitutionality of a statute that it is charged with implementing and that it is appropriate for the Commission to assume the validity of such a statute until there is a judicial decision to the contrary. The Commission adheres to that ruling in the present proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Mr. Dickey in his prefiled testimony referred to a November 1990 Stone & Webster study. The results of that study showed a negative net present value associated with extending service to Alexander, Warren and McDowell Counties. By motion raised at the hearing on August 25, 1992, CUCA moved to strike those portions of Mr. Dickey's prefiled testimony related to the Stone & Webster study on grounds of hearsay. The Commission took the motion under advisement pending development of the record. When he took the stand on August 25, Mr. Dickey testified that in his own opinion service to these areas would be economically infeasible. He stated

> [J]ust from the experiences I have being in the gas business the period of time I have been, I have my own opinion that these are uneconomic projects. We're in the business to supply gas to communities and we want to serve those areas that are economically feasible to serve. Had these areas been feasible in our opinion, then, we would have been making progress toward serving those areas. So, I am [convinced], as I say, both from observing the study and from my own experience that. . . it is infeasible to serve these counties.

CUCA's motion is denied. First, Mr. Dickey's direct testimony was prefiled on June 30, but CUCA did not file its motion until the day of the hearing. The motion was thus untimely. Commission Rule R1-24(g)(4). Moreover, the Stone & Webster data summarized and referred to by Mr. Dickey is clearly admissible under Rule 703 of the North Carolina Rules of Evidence as the basis for his opinion testimony. Finally, the motion is moot. The subsequent Deloitte & Touche study was admitted into the record without objection, and Mr. Dickey gave testimony based upon that material. Under the circumstances, no purpose would be served by striking the previous testimony of Mr. Dickey. Accordingly, CUCA's motion to strike is denied.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding is contained in the Petition and the Supplemental Request and the record of this proceeding as a whole. Mr. Dickey testified that the notice requirements contained in the Commission's Orders of June 10, 1992, and October 30, 1992, have been satisfied.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-11

The evidence for these findings is contained in the testimony of Public Service witness Dickey, Public Staff witness Sessoms, and the public witnesses.

In order to establish an expansion fund for a natural gas public utility, the Commission must find that there are unserved areas within the company's franchised territory in which it would otherwise not be feasible for the company to construct natural gas facilities. G.S. 62-158(a). The Commission must also find that it is in the public interest to establish an expansion fund. Commission Rule R6-82(d); see also G.S. 62-2(9).

In the rulemaking proceedings to implement G.S. 62-158, the Commission defined unserved areas in Rule R6-81(b)(5) as counties, cities or towns of which a high percentage is unserved. It is undisputed that Public Service presently does not serve three entire counties within its franchised territory. Those counties are Alexander, Warren and McDowell. Further, the Company currently has only limited facilities in Franklin County and in Haywood County. Public Service witness Dickey testified based on his experience that it is infeasible to extend service to the five counties under a conventional financial analysis and using traditional financing methods. He further testified that his opinion was both consistent with the Deloitte & Touche study and reinforced by the overall results of the study. The Deloitte and Touche study showed expansion into the five counties to have a negative net present value of approximately $25 million. Public Staff witness Sessoms testified that while he did not necessarily agree with the amount of the negative net present value calculated by Deloitte & Touche, it is not feasible in his opinion to construct transmission lines into the counties of Alexander, Franklin, Haywood, McDowell and Warren at this time. Based on the foregoing, the Commission concludes that Public Service has unserved areas and that expansion into the unserved counties is not economically feasible using traditional financing methods.

The next requirement is that the Commission find establishment of an expansion fund to be in the public interest. Witness Dickey testified that Public Service believes the creation of an expansion fund for it is consistent with the public policy expressed in G.S. 62-2(9) and G.S. 62-158. He further testified that Public Service had made the showing that is required for the establishment of an expansion fund and that the establishment of an expansion fund for Public Service is in the public interest. Public Staff witness Sessoms pointed out that the Commission found in its NCNG Order that the General Assembly has made the policy decision that it is necessary and in the public interest to authorize special funding methods to facilitate the construction of facilities and the extension of service into unserved areas where it would not be economically feasible to expand with traditional methods in order to provide infrastructure to aid industrial recruitment and economic development. He testified that the General Assembly's policy decision also should apply to Public Service. The Public Staff believes that when the petitioning LDC does not request approval of a specific expansion project, it must express a specific intention to extend natural gas facilities into one or more of its unserved areas if disbursements from an expansion fund are made available. Public Service witness Dickey testified that Public Service would be prepared to move forward with the filing of specific projects upon issuance of the Commission's final order establishing an expansion fund. He testified that he would expect Public Service to file within three months of the issuance of a final order.

As to the requirement of public interest, the Commission finds first and foremost that the General Assembly has largely made this policy decision already. G.S. 62-158 is the culmination of years of work through the General Assembly to expand natural gas service. Throughout this time, local industrial recruiters and government officials have argued the need for natural gas service in their areas in order to achieve economic development.

The General Assembly held several meetings in the late 1980s to explore the status of natural gas service in the State and the reason for unserved counties existing within the utilities' franchised territories. The General Assembly enacted G.S. 62-36A in June 1989. This statute provides for the natural gas utilities to submit reports detailing their plans for providing natural gas service to areas of their territories in which such service is not available and for the Commission and Public Staff to analyze and summarize these reports independently and provide analyses and status reports to the Joint Legislative Utility Review Committee on a biennial basis. The LDCs filed their reports in January 1990 and in January 1992. The Commission and the Public Staff submitted their analyses to the Committee in May of 1990 and in May of 1992.

Following the receipt of the first set of analyses pursuant to G.S. 62-36A, the General Assembly began focusing on new financing methods to facilitate the extension of natural gas service and G.S. 62-158 was enacted on July 8, 1991. The preamble to the legislation specifically states that the reports of the utilities, the Commission and the Public Staff indicated that the construction of facilities and the extension of natural gas service in some areas of the State may not be economically feasible with traditional funding. The preamble to the legislation specifically states that the General Assembly finds it necessary and in the public interest to authorize special funding methods to facilitate the construction of facilities in and the extension of natural gas service to unserved areas in the utilities' territories that would otherwise not be feasible. Further, the General Assembly adopted G.S. 62-2(9), which provides that it is the public policy of the State to facilitate the construction of natural gas facilities and the extension of natural gas service to promote the public welfare throughout the State and to authorize the creation of expansion funds to that end.

Thus, it is clear to the Commission that the General Assembly has made the policy decision that it is necessary and in the public interest to authorize the special funding methods provided by G.S. 62-158 to facilitate the construction of facilities and the extension of natural gas service into unserved counties in the State where it would be economically infeasible to serve by traditional means in order to provide infrastructure to aid industrial recruitment and economic development. Once we have found unserved areas that are otherwise infeasible to serve, the Commission believes that the General Assembly intends for the Commission to exercise limited discretion as to whether a fund should be created for that particular natural gas utility.

Several witnesses addressed the issue of public interest in their testimony, and the Commission finds that this testimony bolsters the finding of public interest in this case. Mr. Dickey testified:

> Expansion of natural gas service into these [unserved] areas will improve the chances for industrial development in portions of the State which presently are unable to attract certain gas-consuming

industries. Industrial expansion will bring jobs, additional residential and commercial development, and increases in tax base to these counties.

Mr. Abernathy and Mr. Harmon, based on their extensive experience in industrial development activities, testified that approximately one-third of all potential industries seeking to relocate list natural gas as a requirement. Mr. Edwards testified similarly. Mr. Glass testified that natural gas "means jobs, it means lower industrial costs, a better qualify of life for our citizens." He further stated, "In the past six years, we have greatly improved our educational system, dramatically enlarged our water distribution system, sought regional cooperation in other public services, such as solid waste and recycling. Natural gas is the missing link in the chain that will strengthen public services in our county." Similarly Mr. Birdsong testified that "natural gas is one of those items that is important when you're talking about economy growth." This testimony tends to show that expansion of natural gas facilities into unserved areas by use of expansion funds will assist in the economic development of unserved areas in Public Service's franchised territory. Economic development brings with it a larger tax base, more employment opportunities and a better quality of life. Moreover, present customers on the Company's system stand to benefit from expansion made possible by the natural gas expansion fund. Mr. Dickey testified that there is benefit to all gas customers to the extent that economic development does occur, in that it will tend to lower overall rates in the future (or moderate increases in rates that might otherwise occur) due to the spreading of fixed costs over larger volumes. Thus, the testimony bolsters the finding that creation of an expansion fund for the Company is in the public interest, and the Commission concludes that an expansion fund should be established.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-16

The evidence for these findings of fact is found in the testimony of Company witness Dickey and Public Staff witness Hoard.

Use of supplier refunds to a local distribution company as expansion funds is explicitly authorized under G.S. 62-158(b). This Commission's practice has been to return such supplier refunds to customers consistent with the authority granted the Commission by G.S. 62-136(c). The Commission would have done so here but for the provisions of G.S. 62-158.

Company witness Dickey originally proposed that Public Service be allowed to deposit in the expansion fund (1) a supplier refund of $5,815,870, plus applicable interest, which is contingent upon the resolution of an appeal by its interstate pipeline supplier Transco and (2) additional supplier refunds of $214,900, plus approximately $21,000 per month that will continue to be received through July 1994 in connection with FERC Docket Nos. RP 88-68, et al., IN 89-1-000, and IN-89-1-001.

By the Supplemental Request filed September 11, 1992, Public Service requested that two additional supplier refunds received subsequent to the filing of its petition be approved for deposit into the expansion fund. These refunds were (1) a Transco refund in the amount of $4,288,946 received August 7, 1992, and (2) a payment of $51,526, received July 6, 1992, as a result of a Producer Settlement Payment charges true-up.

Public Service witness Dickey testified at the March hearing that Public Service had withdrawn its request to deposit the contingent Transco refund and would stipulate to the amount of supplier refunds that the Public Staff had determined to be eligible and appropriate for deposit into an expansion fund. Mr. Dickey agreed to the Public Staff's recommendation that $4,774,840, plus the additional monthly supplier refunds of approximately $21,000 each through July 1994, plus interest, is the appropriate amount to be transferred to the expansion fund. The calculation of the $4,774,840 figure is in Hoard Exhibit 1. The Commission concludes that the testimony and findings support funding of this general order.

The Company requested that the remainder of its uncontested supplier refunds (which have not been noticed to the public) and the Transco refund contingent on appeal be maintained in a separate account pending further action by the Commission. The Commission concludes that these funds should continue to be held.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-19

The evidence for these findings is in the testimony of Public Staff witness Hoard and the orders and records of the Commission.

The Commission presently retains Washington, D.C. legal counsel for the purpose of representing it before the Federal Energy Regulatory Commission. In addition, the Commission and Public Staff incur travel costs from time to time in order to assist the Commission's legal counsel. Pursuant to G.S. 62-48, the Commission is reimbursed for these costs by the LDCs out of supplier refunds. The statute also provides for the Commission to establish procedures for the LDCs to set aside reasonable amounts of supplier refunds for these purposes. The Commission has developed generic procedures to deal with setting aside reasonable amounts of supplier refunds for purposes of G.S. 62-48 by separate order dated February 23, 1993, in Docket No. G-100, Sub 57.

Public Staff witness Hoard testified that the balance in Public Service's account for paying the Commission's Washington, D.C. legal counsel and related travel costs, Account 253.03, was $49,220 as of January 31, 1993. He further testified that this balance is adequate at this time.

Based on the foregoing the Commission concludes that the balance in Public Service's Account 253.03 is adequate at this time and that future deposits into this account will be handled in accordance with the procedures set out in the Commission's generic order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

Commission Rule R6-82(d) provides that the Commission shall require "appropriate notice of its decision" when an expansion fund is established. The Commission concludes that Public Service shall provide notice to its customers by bill insert that an expansion fund has been established and that supplier refunds have been transferred to it in order to carry out the intent of the General Assembly as expressed in G.S. 62-158.

IT IS, THEREFORE, ORDERED as follows:

1. That an expansion fund for Public Service shall be created in the Office of the State Treasurer for the purpose of constructing natural gas lines into unserved areas in its franchised territory that would otherwise be infeasible to serve in order to provide infrastructure to aid industrial recruitment and economic development;

2. That Public Service is hereby directed to transfer to the Commission for deposit in Public Service's expansion fund the sum of $4,774,840 as calculated in Hoard Exhibit 1, plus the additional monthly supplier refunds since calculation of Hoard Exhibit 1 and through July 1994 in connection with FERC Docket Nos. RP 88-68, et al., IN 89-1-000, and IN 89-1-001, plus applicable interest; that Public Service shall remit funds currently held by it on the next maturity date of the financial instruments in which they are currently invested so as to avoid any penalty for premature withdrawal; and

3. That Public Service shall notify its customers of the Commission's decision by sending a copy of the Notice attached hereto as Appendix A as a bill insert in its next billing cycle.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-5, SUB 300

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by Public Service Company of North Carolina to Authorize Establishment of a Natural Gas Expansion Fund Pursuant to G.S. 62-158	)	PUBLIC NOTICE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission, upon petition of Public Service Company of North Carolina and following a hearing at which several parties participated and presented testimony, entered an Order on June 3, 1993, establishing an expansion fund for Public Service and approving initial funding of the expansion fund in order to carry out the intent of the General Assembly as expressed in G.S. 62-158.

G.S. 62-158 was enacted by the General Assembly on July 8, 1991. The statute authorizes the Utilities Commission to "order a natural gas local distribution company to create a special natural gas expansion fund to be used by that company to construct natural gas facilities in areas within the company's franchised territory that otherwise would not be feasible for the company to construct." The statute goes on to provide that sources of funding for such an expansion fund may include "refunds to a local distribution company from the company's suppliers of natural gas and transportation services pursuant to refund orders or requirements of the Federal Energy Regulatory Commission."

Public Service petitioned the Commission to create an expansion fund and to transfer certain supplier refunds to the expansion fund. The Commission's Order created an expansion fund and ordered Public Service to transfer refunds totaling approximately $5.1 million, plus interest, to the expansion fund pursuant to G.S. 62-158.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. G-9, SUB 332

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas Company, Inc., for an Adjustment of its Rates and Charges to Track Changes in Its Wholesale Cost of Gas	)	ORDER APPROVING OFFSET OF GAS COST INCREASE

BY THE COMMISSION: Piedmont Natural Gas Company, Inc. (Piedmont), filed an application on January 7, 1993, pursuant to G.S. 62-133.4, Commission Rule R1-17(k)(3), and Appendix A of Piedmont's North Carolina Service Regulations seeking to recover increases in its wholesale cost of gas. Piedmont stated that since its last gas cost true-up, for a period ended May 31, 1992, it had undercollected $5,889,100 in commodity gas costs through November 30, 1992. The undercollection has occurred as a result of (1) a Transco rate change under the provisions of Section 4 of the Natural Gas Act, (2) new contracts with pipelines and suppliers, and (3) commodity price increases under existing gas supply contracts. If Piedmont were to increase its rates over a twelve-month period din order to collect this amount, a rate increase of $.1208 per dekatherm (dt) would be necessary.

Piedmont further stated that it had $10,715,510 of refunds which it had placed in various accounts for utilization under G.S. 62-158. Of this amount, $5,510,130 is being held subject to possible refund to Transco, leaving an unencumbered refund balance for potential expansion fund purposes of $5,205,380. Piedmont stated that it did not presently contemplate having a need of the unencumbered balance for expansion purposes and requested permission to offset the gas cost increase in order to avoid a rate increase.

The Public Staff brought this matter to the Commission's regular staff conference on January 25, 1993, and recommended that the Commission authorize the offset as proposed by Piedmont.

The Commission, upon recommendation by the Public Staff, finds good cause to approve the offset of gas cost increases with the unencumbered refund balance for expansion purposes as requested by Piedmont.

IT IS, THEREFORE, ORDERED as follows:

That Piedmont Natural Gas Company, Inc., is hereby authorized to offset its additional gas costs with the unencumbered balance of refunds held for potential expansion fund purposes pursuant to G.S. 62-158 of $5,205,380.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of January 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-21, SUB 314

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of North Carolina Natural Gas Corporation for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)

ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, April 6, 1993, at 10:00 a.m., Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Allyson K. Duncan, Presiding; and Commissioners Robert O. Wells and Charles H. Hughes

APPEARANCES:

FOR NORTH CAROLINA NATURAL GAS CORPORATION:

Donald W. McCoy, Attorney at Law, Jeffrey N. Surles, Attorney at Law, McCoy, Weaver, Wiggins, Cleveland & Raper, Post Office Box 2129, Fayetteville, North Carolina 28302

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, Post Office Drawer 1269, Morganton, North Carolina 28655

FOR THE USING AND CONSUMING PUBLIC:

Antoinette R. Wike, Chief Counsel, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On January 29, 1993, North Carolina Natural Gas Corporation (NCNG) filed the direct testimony and exhibits of Gerald A. Teele, Senior Vice President and Chief Financial Officer of NCNG, relating to the annual prudence review of NCNG's gas costs pursuant to N.C.G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

On February 15, 1993, the Commission issued its Order scheduling a public hearing for April 6, 1993, setting dates for pre-filed testimony and intervention in this docket and ordering NCNG to publish Notice of these matters in a form of notice attached to the Commission's Order.

On March 18, 1993, Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to intervene which petition was allowed by the Commission on March 19, 1993.

The Public Staff filed the direct testimony of Windley E. Henry, Staff Accountant, on March 22, 1993. CUCA did not pre-file testimony in this proceeding. NCNG witness Gerald A. Teele and Public Staff witness Windley E. Henry, were the only witnesses who testified at the public hearing on April 7, 1993. NCNG filed Affidavits of Publication evidencing the publishing of the notices required by the Commission and such Affidavits were entered into evidence at the start of the hearing.

Based on the testimony and exhibits and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACTS

1. NCNG is a public utility as that term is defined in Chapter 62 of the North Carolina General Statutes.

2. NCNG primarily is engaged in the purchase, distribution and sale of natural gas (and in some instances, the transportation of customer-owned gas) to more than 123,000 customers in south central and eastern North Carolina.

3. NCNG has filed with the Commission and submitted to the Public Staff all of the information required by N.C.G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The test period for review of gas costs in this proceeding is the twelve months ended November 30, 1992.

5. During the period of review, NCNG incurred gas costs of $109,488,165, received $110,955,015 in recovery of gas costs through its rates, made direct refunds to its customers of $12,231,945 (net of gross receipts tax) and refunded to its customers a net amount of $10,455,528 through decrements in its rates.

6. On November 30, 1992, NCNG had a $9,870,616 debit balance in its deferred accounts.

7. The Public Staff took two exceptions to NCNG's accounting for gas costs and recoveries and NCNG agreed to make and did make correcting journal entries as of February 28, 1993 (1) to reverse the sum of $57,000 charged to the deferred

account as accrued interest in connection with Columbia Gas Inventory charge and (2) to credit the deferred account $140,000 associated with the computation of fixed gas cost recovery.

8. NCNG has properly accounted for its gas costs during the period of review and the correcting journal entries are proper.

9. NCNG has transportation and supply contracts with the interstate pipelines which transport gas directly to NCNG's system and long term supply contracts with seven other suppliers.

10. NCNG has made prudent gas purchasing decisions and all of the gas costs incurred by NCNG during the period of review were prudently incurred.

11. NCNG should be permitted to recover 100% of its prudently incurred gas costs.

12. NCNG has an increment in its sales rates of $0.1584 per dekatherm (dt) for the Deferred Gas Cost-Sales Customers Account approved by the Commission effective November 1, 1992.

13. The $.1584 per dt increment in NCNG's rates netted against projected over-recoveries of gas costs during 1993 should reduce substantially NCNG's deferred account balance making an additional increment in NCNG's rates to reduce the deferred account balance unnecessary at this time.

14. It is just and reasonable to continue the $.1584 per dt increment in NCNG's sales rates until further order of the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence for these findings of fact is contained in the official files and records of the Commission and the testimony of NCNG witness Teele. These findings are essentially informational, procedural or jurisdictional in nature and are facts uncontradicted by any of the parties.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings of fact is contained in the testimony of NCNG witness Teele and the findings are based on N.C.G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

N.C.G.S. 62-133.4 requires that NCNG submit to the Commission information and data for a historical twelve-month test period which information and data include NCNG's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes and transportation volumes. In addition to such information, Commission Rule R1-17(k)(6)(c) requires that there be filed weather-normalized sales volume data, work papers and direct testimony and exhibits supporting the information filed.

Witness Teele testified that Commission Rule R1-17(k)(6) required NCNG to submit to the Commission on or before February 1, 1993, the required information based on a twelve-month test period ending November 30, 1992. Witness Teele testified that NCNG complied with the filing requirements of N.C.G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) and an examination of witness Teele's testimony and exhibits confirms the same. Witness Teele also testified that NCNG filed with the Commission and submitted to the Public Staff throughout the review period complete monthly accountings of the computations required by Commission Rule R1-17(k)(5)(c). Public Staff witness Henry confirmed that the Public Staff had reviewed the filings and that they complied with the Rules.

The Commission concludes that NCNG has complied with all the procedural requirements of N.C.G.S. 62-133.4(c) and Commission Rule R1-17(k) for the twelve-month review period ended November 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings of fact is found in the testimony of NCNG witness Teele and Public Staff witness Henry.

NCNG witness Teele testified that at the beginning of the twelve-month review period, NCNG had a net credit balance in its deferred accounts totalling $12,082,043. Although NCNG had a decrement in its sales rates of $.6578 through the 1991-1992 winter, it over-recovered gas costs by a net amount of $10,803,000 due primarily to rapidly falling gas prices during the 1991-1992 winter period. At the request of the Public Staff and with the consent of NCNG, the Commission ordered NCNG to make a direct refund of $12,639,000 from the deferred gas cost account to sales customers during the Spring of 1992.

Witness Teele testified that due to unusual gas price swings during the review period and due to delays in tracking in NCNG's rates the gas cost increases incurred by NCNG subsequent to February 1992, NCNG under-recovered its gas costs over much of the remaining months of the review period. As a result, the balance in NCNG's deferred accounts as of November 30, 1992, was a debit balance of $9,870,616 which consisted of $8,339,125 in the commodity deferred account (sales customers only) and $1,531,491 in the demand deferred account (all customers).

Witness Henry testified that the Public Staff had examined NCNG's accounting for gas costs during the review period and determined that NCNG had properly accounted for its gas costs with two exceptions. According to witness Henry, the first exception was the failure to reverse $57,000 in accrued interest charged to the deferred account as a result of Columbia's gas inventory charge. The second exception by the Public Staff related to a fixed cost recovery rate used by NCNG in computing fixed gas cost recoveries on negotiated non-IST volumes. NCNG recorded journal entries as of February 28, 1993, reversing the interest charged on the Columbia gas inventory amounting to $57,000 and crediting the deferred account $140,000 related to the fixed gas cost recovery charges. These journal entries by NCNG resolved both exceptions taken by the Public Staff. The Commission takes judicial notice of NCNG's filing dated April 15, 1993, in Docket G-21, Sub 293, related to the fixed gas cost recovery rate issue raised by the Public Staff which filing clarifies the language in the tariff dealing with fixed gas cost recoveries and makes the tariff consistent with the Public Staff's position.

Based upon the testimony and exhibits of the witnesses, the monthly filings by NCNG as required by Commission Rule R1-17(k)(5)(c) and the findings of fact set forth above, the Commission concludes that NCNG has properly accounted for gas costs during the period of review.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-14

The evidence supporting these findings of fact is found in the testimony of NCNG witness Teele and Public Staff witness Henry.

Witness Teele testified that the primary objective of NCNG's Board of Directors' gas supply acquisition policy is to insure that the company has adequate volumes of competitively priced natural gas to meet the peak day demands of all firm customers on its system and to provide the maximum service possible to all customers during other times throughout the year. Witness Teele testified that NCNG takes steps to keep its gas costs as low as possible commensurate with its gas supply acquisition policy including participation at the FERC, its active business relationships with at least twenty (20) gas suppliers, its work with customers to negotiate rates or arrange transportation in order to maintain throughput, its internal gas supply/gas control committee which meets on a regular basis and its overall management, planning and review. Witness Teele testified that NCNG also monitors carefully the energy markets and communicates daily with its pipelines and gas suppliers.

NCNG sells or transports gas to two markets. Its firm market is principally residential, commercial and small industrial customers and its interruptible market principally is large industrial and electric power generation interruptible customers. NCNG's firm market also includes customers who have firm contracts for the purchase or transportation of certain volumes of gas and demand charges in their rates, including NCNG's four municipal customers. Witness Teele noted that due to the need for secure supplies, NCNG's firm market is the primary recipient of gas under its long term contracts while NCNG buys spot gas, usually in the summer months, to supply a portion of its interruptible markets which are price-sensitive.

Witness Teele testified that NCNG uses a portfolio approach in gas supply planning with an emphasis on price, security of supply, and flexibility. NCNG has long-term transportation and supply contracts with Transcontinental Gas Pipeline Corporation and Columbia Gas Transmission Corporation, the two interstate pipelines which provide direct service to NCNG's system. NCNG also has entered into contracts with seven other suppliers including major producers. NCNG's current long-term contracts cover approximately 190,000 dekatherms per day for winter delivery and lesser amounts in the remainder of the year.

Public Staff witness Henry testified that the Public Staff had two people from accounting, a staff attorney, and an engineer from the gas section of the Public Staff involved in the review of NCNG's gas supply contracts and gas costs. Witness Henry testified that the Public Staff served NCNG with data requests to which NCNG responded in full. The Public Staff reviewed the responses to data requests, NCNG's testimony and exhibits in this docket, the monthly information submitted by NCNG on gas costs for the review period and NCNG's gas purchase and transportation contracts. According to witness Henry, the Public Staff compared NCNG's gas purchase and transportation contracts to those contracts entered into by other gas utilities in North Carolina, examined NCNG's markets, purchasing practices and peak day responsibilities and analyzed NCNG's purchasing practices in light of the annual and peak day requirements of its system. Based upon such examination, Public Staff witness Henry testified that in the Public Staff's opinion, NCNG's purchasing practices were reasonable and prudent.

The attorney for CUCA announced near the beginning of his cross-examination of NCNG witness Teele that CUCA was not questioning the prudence of the gas costs incurred by NCNG during the review period. The Commission concludes that the gas costs incurred by NCNG during the twelve-month period of review ended November 30, 1992 were reasonable and prudently incurred.

CUCA argues that the Commission should require the Company and the Public Staff to present more detailed testimony concerning prudence in future proceedings. CUCA concedes that the Public Staff made an extensive investigation, and it concedes that the transcript includes evidence on raw gas supply and transportation costs, NCNG's purchasing practices, and opinion testimony from both the Company and the Public Staff that the Company's gas supply and transportation costs had been prudently incurred. Still, CUCA argues that the Commission does not have a sufficient basis for making a prudency determination, and it argues that the Public Staff should present the results of its investigation in more detail so that others, presumably CUCA itself, will have more information in future proceedings. The Commission concludes that the record includes a sufficient basis for the prudency determination that it has made. The Commission notes that we are in an early stage of implementing G.S. 62-133.4 and new Commission Rule R1-17(k). Should any party feel in the future that the Commission should require more in the way of filing requirements or testimony, the appropriate course would be a generic motion to reopen the rulemaking proceeding in Docket G-100, Sub 58.

CUCA also questions the fairness of using equal per dekatherm rate changes in proceedings under G.S. 62-133.4. CUCA concedes that it made a similar argument in Docket No. G-100, Sub 58, and that the Commission rejected its position. CUCA amplifies its arguments and urges that Commission "acting on its own motion, reopen Docket No. G-100, Sub 58, in order to examine whether changes in the nature persistently advocated by CUCA should be made. . . " The Commission only recently concluded the rulemaking proceeding in Docket No. G-100, Sub 58, and we find no reason to reexamine our decisions or to reopen that docket now.

NCNG witness Teele testified that NCNG has in its sales rates an increment of $.1584 per dt which was approved by the Commission effective November 1, 1992, to reduce the debit balance in the Deferred Gas Cost-Sales Customers' Account. The $.1584 per dt increment was designed based on anticipated gas sales over a twelve-month period ending October 31, 1993. NCNG witness Teele testified that NCNG proposes to recover the debit balance in its deferred account, which was $9.8 million on November 30, 1992, through the increment of $.1584 per dt on sales rates and netted against over-recoveries of gas costs during the remainder of 1993. Witness Teele testified that NCNG prefers not to propose an additional increment in its rates unless the deferred account balances do not come down according to plan.

On cross-examination, witness Teele testified that NCNG's deferred accounts had a total debit balance as of February 28, 1993, of $2,481,427 of which $2,989,108 is a debit balance in the commodity deferred account (sales customers only) with a credit balance to all customers for the demand components of $1,282,655 and a separately stated debit for the Columbia Gas Inventory charge of $774,974. The Commission believes that it is just and reasonable to continue the $.1584 per dt increment in NCNG's sales rates until further order by the Commission as the decrease in the deferred account debit balance indicates that no further increment is necessary at this time. Should the debit balance not be eliminated as planned by NCNG, NCNG may request an additional increment or decrement in its rates at a later date if the balance in the deferred account does not return to zero.

IT IS THEREFORE ORDERED as follows:

1. That NCNG's accounting for gas costs and recoveries during the twelve-month period of review ended November 30, 1992, subject to the adjustments agreed to by the Public Staff and NCNG, be, and the same hereby is, approved;

2. That NCNG be, and it hereby is, authorized to recover 100% of its gas costs incurred during the twelve-month period of review ended November 30, 1992, as the same are reasonable and prudently incurred;

3. That the increment of $.1584 per dekatherm approved by the Commission effective November 1, 1992, for the Deferred Gas Cost-Sales Customers' Account shall continue in NCNG's sales rates until further order of the Commission.

ISSUED BY ORDER OF THIS COMMISSION.
This the 15th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-9, SUB 332

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Its Rates and Charges	)	ORDER APPROVING TRANSFER OF FUND

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on September 30, 1993

BEFORE: Commissioner Lawrence A. Cobb, presiding, Chairman John E. Thomas, and Commissioners William W. Redman, Allyson K. Duncan and Judy Hunt

APPEARANCES:

For the Applicant:

Jerry W. Amos, Brooks, Pierce, McLendon, Humphrey & Leonard, Attorneys at Law, Post Office 26000, Greensboro, North Carolina 27420

For the Public Staff:

Antoinette R. Wike, Chief Counsel, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

For the Attorney General:

Margaret A. Force, Associate Attorney General, Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Box 1269, Morganton, North Carolina 28680-1269

BY THE COMMISSION: This matter is before the Commission upon the petition of Piedmont Natural Gas Company, Inc. (Piedmont) filed on May 12, 1993. In that petition, Piedmont requests the Commission to permit Piedmont to return $1,662,007 to its expansion fund escrow account. On May 27, 1993, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, and that petition was granted by Commission order of June 9, 1993. On September 27, 1993, the Attorney General filed a notice of intervention.

On June 3, 1993, the Commission set the matter for hearing on September 30, 1993, directed Piedmont to file its testimony by August 12, 1993, and directed any intervenors and the Public Staff to file their testimony by September 9, 1993. Testimony was timely filed on behalf of Piedmont by Ware F. Schiefer and on behalf of the Public Staff by James G. Hoard. Neither CUCA nor the Attorney

General filed any testimony. On September 22, 1993, the Public Staff moved to strike certain portions of the testimony of Piedmont witness Schiefer, and that motion was granted on September 30, 1993.

On September 20, 1993, CUCA filed a motion to dismiss Piedmont's petition on the grounds that G.S. § 62-158 is unconstitutional. Piedmont filed a response on September 23, 1993, and CUCA filed a reply on September 30, 1993.

The matter came on for hearing as scheduled. Piedmont witness Schiefer testified that Piedmont filed an application with the Commission in this docket on January 5, 1993. In that application, Piedmont requested permission to use the $5,205,380 unencumbered balance of its expansion fund escrow account to offset an increase in its gas costs. On January 26, 1993, the Commission issued an order granting Piedmont's request. On May 12, 1993, Piedmont filed the petition which is the subject of this hearing. In that petition, Piedmont advised the Commission that it did not require the full $5,205,380 unencumbered balance to offset the gas cost increase and requested the Commission to permit it to return the unused balance of $1,662,007 to the expansion fund escrow account. Witness Schiefer gave two reasons to support Piedmont's request. First, since Piedmont only needed $3,543,373 of the escrow funds to offset the increased gas costs in question, the unused balance of $1,662,007 should be returned to the expansion fund. Second, returning the funds to the escrow account is consistent with the clear objective of the General Assembly to provide funds for expansion of gas service. On cross-examination, Witness Schiefer testified that Piedmont presently has $919,000 of unrestricted funds in the expansion fund escrow account and $5.8 million of funds being held subject to the final outcome of an appeal, and that Piedmont anticipates receiving additional refunds from its suppliers to be placed in the expansion fund escrow account. He also testified that Piedmont has made an economic analysis for the use of expansion funds for various projects but has not yet filed the analysis because of the pending appeal of the constitutionality of G.S. § 62-158 and the need to avoid getting expectations up that may not be fulfilled. On re-direct, Witness Schiefer testified that the amount required by the economic analysis is in excess of the amount that is expected to be placed in the expansion fund escrow account from all presently known sources.

The Public Staff witness Hoard recommended that the Commission approve Piedmont's request conditioned upon Piedmont including in its January 1, 1994 biennial expansion plan update an expansion project of the type contemplated by G.S. § 62-158 which Piedmont intends to undertake. Witness Hoard testified that the Public Staff fully supports the General Assembly's goal to expand natural gas service into unserved areas, but is concerned with the accumulation of large sums for expansion projects when Piedmont has not yet presented the Commission with a project which could receive the expansion project funding authorized by G.S. § 62-158. Witness Hoard testified on direct that the recommended condition should provide a test of Piedmont's intent regarding expansion projects of the type contemplated by G.S. § 62-158 and also provide the Commission with information regarding the costs of potential major expansion projects by Piedmont. On cross-examination, Witness Hoard testified that his concern is not that Piedmont is unwilling to use the expansion funds to expand its service area, but rather that Piedmont may use the expansion funds to expand in areas where the Public Staff thinks the use of such funds would be improper.

The Commission has carefully considered the testimony of the witnesses, the various documents of which it took judicial notice at the hearing and the entire record in this case, and based upon undisputed facts, the Commission concludes that Piedmont's petition should be granted. The issue before the Commission in this case is quite limited: should Piedmont be permitted to return $1,662,007 to the expansion fund escrow account? The Commission is not being asked to authorize the expenditure of these funds for any purpose. If the funds are returned to the escrow account, they remain subject to the jurisdiction of the Commission. In the Commission's Order Regarding Handling of Supplier Refunds by Local Distribution Companies issued in Docket No. G-100, Sub 57, on March 12, 1992, the Commission make it clear that all monies held in this escrow account are subject to "further order of the Commission as to their appropriate disposition." If the Supreme Court rules that G.S. § 62-158 is constitutional and if the Commission approves an expansion project for Piedmont complying with the requirements of that statute, the funds can be used for such expansion. If the Court rules that G.S. § 62-158 is unconstitutional, the Commission can order Piedmont to make an appropriate disposition of the funds. The Commission's decision to return the $1,662,007 to the expansion fund escrow account does not prejudice any party.

The Commission has considered the Public Staff's request that the Commission condition the approval of Piedmont's request upon Piedmont including in its January 1, 1994 biennial expansion plan update an expansion project of the type contemplated by G.S. § 62-158 which Piedmont intends to undertake. Although the Commission encourages Piedmont to inform the Commission and the Public Staff of potential projects of the type contemplated by G.S. § 62-158, the Commission understands Piedmont's concern about raising expectations that cannot be fulfilled, at least while the constitutionality of the statute is being challenged on appeal. Therefore, the Commission will not order Piedmont to make such a filing at this time. If the statute is held to be constitutional, however, Piedmont will be required to amend its expansion plan update to include analyses of potential projects, including projects for which additional franchised territory would be requested, within sixty days of the Court's decision.

In its September 18, 1993 motion to dismiss, CUCA argues that G.S. § 62-158 is unconstitutional under various provisions of the United States Constitution and the North Carolina Constitution. CUCA made identical arguments in Docket No. G-21, Subs 306 and 307. On February 8, 1993, the Commission issued its order in that docket concluding that "it is appropriate for the Commission to assume the validity of statutes it is charged with implementing until there is a judicial decision to the contrary." The Commission finds nothing to justify departing from its earlier ruling on this issue. The Commission concludes that it has no authority to rule on CUCA's motion to dismiss.

On November 9, 1993, CUCA filed a proposed order in which it argues that Piedmont will receive supplier refunds eligible for inclusion in its expansion fund escrow account in an amount well in excess of any reasonable estimate of the negative net present value of extending service to all unserved areas in Piedmont's franchised territory. Therefore, CUCA argues that the present petition should be denied and that the money at issue should remain in Piedmont's deferred account where it will serve to lower the utility bills of existing ratepayers. The Commission rejects this argument. First, we cannot now make any determination as to the negative net present value of extending service to unserved areas of Piedmont's territory. That is an issue for another day and another docket. Further, as already noted, all monies in Piedmont's expansion fund escrow account are subject to further order of the Commission as to their appropriate disposition. The present Order makes no decision as to the ultimate disposition of the money involved herein.

IT IS, THEREFORE, ORDERED that Piedmont Natural Gas Company, Inc., should be, and hereby is, authorized to return $1,662,007 from its deferred account to its expansion fund escrow account where it will remain pending further order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of December 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-5, Sub 318

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, August 10, 1993, at 10:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman John E. Thomas, Presiding; and Commissioners William W. Redman and Lawrence A. Cobb

APPEARANCES:

FOR PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.:

William A. Davis, II, Attorney at Law, Tharrington, Smith & Hargrove, Post Office Box 1151, Raleigh, North Carolina 27602-1151

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, Post Office Drawer 1269, Morganton, North Carolina 28655-1269

FOR THE USING AND CONSUMING PUBLIC:

Gisele L. Rankin, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On June 1, 1993, Public Service Company of North Carolina, Inc. (Public Service or the Company) filed the direct testimony and exhibits of Franklin H. Yoho, Vice President-Corporate Development and Gas Supply and of Bruce P. Barkley, Manager of Rates and Regulatory Administration for the Company in connection with the annual prudence review of Public Service's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

On June 29, 1993, the Commission issued its Order scheduling a public hearing for August 10, 1993, setting dates for pre-filed testimony and intervention in this docket and ordering the Company to publish notice in these matters in a form of notice attached to the Commission's Order.

On July 21, 1993, Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene, which was allowed by the Commission by Order dated July 23, 1993.

The Public Staff filed the direct testimony of James G. Hoard, Supervisor of the Natural Gas Section in the Accounting Division of the Public Staff on July 30, 1993. CUCA did not prefile testimony in this proceeding. Public Service witnesses Franklin H. Yoho and Bruce P. Barkley and Public Staff witness James G. Hoard were the only witnesses who testified at the public hearing on August 10, 1993.

At the hearing, Mr. Barkley testified that public notice as provided for in the Commission's Order had been duly given in newspapers of general circulation within the Company's territory, but that the Company was still in the process of obtaining affidavits of publication from the newspapers involved. By motion made at the hearing, the Company was granted leave to file the affidavits of publication with its proposed order. The affidavits of publication have been duly filed and are hereby entered into the record of the proceeding.

Based on the testimony and exhibits and the entire record in the proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Public Service is a public utility as that term is defined in Chapter 62 of the North Carolina General Statutes.

2. Public Service is engaged in the purchase, distribution and sale of natural gas, and the transportation of customer-owned gas to some 257,000 customers in North Carolina.

3. Public Service has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The test period for review of gas costs in this proceeding is the twelve months ended March 31, 1993.

5. During the period of review, the Company incurred gas costs of $157,569,261 and recovered $158,474,675 through rates charged to its customers. The excess of collections over gas costs ($905,414) was recorded in the deferred cost of gas accounts for inclusion in future refunds to customers. Public Service also refunded $1,639,426 of previously accumulated gas cost overcollections to customers through rate decrements and refunded an additional $12,829,554 through direct bill credits. Separately, overcollections of company use and unaccounted for gas of $248,591 were recorded for subsequent refund.

6. At March 31, 1993, the Company had a balance of $1,649,098 recoverable from customers in its deferred account for sales customers only and a $2,635,558 balance payable to customers in its deferred account for all customers.

7. The Public Staff took no exceptions to the Company's accounting for gas costs and recoveries during the review period.

8. Public Service has properly accounted for its gas costs and collections from customers during the period of review.

9. Public Service has adopted a gas supply policy, which it refers to as a "best cost supply strategy" under which three primary areas are emphasized: supply security, operational flexibility, and cost of gas.

10. Public Service has a portfolio of gas supply contracts which include long-term supply contracts with five major producers, three interstate pipeline marketing affiliates, and one interstate pipeline. Most of these contracts have provisions which insure that the pricing remains market sensitive.

11. Public Service has made prudent gas purchasing decisions and all of the gas costs incurred by the Company during the period of review were prudently incurred.

12. Public Service should be permitted to recover 100 percent of its prudently incurred gas costs.

13. The Company does not presently have in place an increment or decrement related to its deferral accounts.

14. A rate decrement of $.0545 per dekatherm applicable to all customers will effect a refund over twelve months of the credit balance in the Company's all customers deferred account. The Commission will approve a simultaneous increase under the provisions of Rule R1-17(k)(3) of $.0545 per dekatherm applicable to sales and transportation rates. The Company is not seeking at this time to collect the amounts owed Public Service from sales customers, and no rate adjustments will be made to reflect the debit balance in the sales only deferred account until further order of the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence for these findings of fact is contained in the official files and records of the Commission. These findings are essentially informational, procedural or jurisdictional in nature and are uncontradicted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings of fact is contained in the testimony of Company witnesses Yoho and Barkley and Public Staff witness Hoard and the findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

The relevant statute, G.S. 62-133.4, requires that Public Service submit to the Commission information and data for a historical 12-month test period, which information and data include the Company's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes and transportation volumes. In addition, Commission Rule R1-17(k)(6)(c) requires that there be filed weather normalized sales volume data, work papers and direct testimony and exhibits supporting the information filed.

Witness Barkley testified that Commission Rule R1-17(k)(6) requires the Company to submit to the Commission the required information based on a 12-month test period ending March 31. Mr. Barkley testified that Commission Rule R1-17(k) was adopted by Order of the Commission dated April 9, 1992, and, therefore, was not technically in effect for the entire month of April, 1992. However, Public Service was operating under interim procedures adopted in its general rate case effective November 1, 1991, which were consistent with the procedures prescribed by Rule R1-17(k). Mr. Barkley stated, therefore, that the Company believes it is appropriate to consider the entire year ended March 31, 1993, for the purposes of this proceeding and he presented information dating back to April 1, 1992, in his testimony and accompanying schedules.

An examination of Mr. Barkley's testimony confirms that the Company has complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6). Mr. Barkley further testified that the Company filed with the Commission and submitted to the Public Staff, throughout the review period, complete monthly accountings of the computations required by Commission Rule R1-17(k)(5)(c) and that he was aware of no outstanding issues with respect to those filings. The Public Staff has not taken issue with any of these filings and they are found to be in conformity with the rules.

The Commission concludes that Public Service has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ended March 31, 1993.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings of fact is found in the testimony of Company witness Barkley and Public Staff witness Hoard.

Company witness Barkley testified that the Company incurred gas costs of $157,569,261 during the period. It collected $158,474,675 from customers and recorded the amount overcollected ($905,414) in the deferred cost of gas accounts for future refund to customers. During the period, Public Service refunded $1,639,426 of previously accumulated gas cost overcollections to customers through decrements to rates and refunded an additional $12,829,554 through direct bill credits to customers. The Company separately recorded $248,591 in overcollections of company use and unaccounted for gas.

At March 31, 1993, witness Barkley testified that the deferred account balance for sales customers was $1,649,098 owed to the Company; the deferred account balance for all customers was $2,635,558 payable to customers.

Witness Hoard testified that the Public Staff had examined the Company's accounting for gas costs during the review period and concluded that the Company had properly accounted for its gas costs during the period. The Public Staff took no exceptions to the Company's gas costs accounting for the period.

Based upon the testimony and exhibits of the witnesses, the monthly filings by the Company as required by Commission Rule R1-17(k)(5)(c) and the findings of fact set forth above, the Commission concludes that Public Service has properly accounted for gas costs during the period of review.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-12

The evidence supporting these findings of fact is found in the testimony of Company witness Yoho and Public Staff witness Hoard.

Mr. Yoho testified that approximately 50% of the Company's market is comprised of deliveries to industrial or large commercial customers which either purchase gas from the Company or transport gas on the Company's system. The majority of these customers have the capability to use a fuel other than natural gas (e.g. distillate fuel oil, residual fuel oil or propane) and will use their alternate fuel when it is priced below natural gas. The remainder of the Company's sales are primarily to residential and small commercial customers. The Company's primary competition for this market segment is electricity.

Mr. Yoho testified that the most appropriate description of the Company's gas supply policy would be a "best cost supply strategy." In developing this strategy, the Company has identified three primary areas of emphasis: supply security, operation flexibility and cost of gas. The first and foremost area of concern, Mr. Yoho testified, is security of gas supply. To maintain the necessary supply security for the Company's firm customers, all of its firm interstate pipeline transportation capacity is backed up by supply contracts providing delivery guarantees or storage. The rationale for this requirement is that during design peak conditions, the Company's interruptible markets would most likely be curtailed.

Mr. Yoho testified that the Company has executed long-term supply agreements and supplemental short-term supply agreements with a variety of suppliers including producers, interstate pipelines, and marketers. Mr. Yoho stated that by developing a diversified portfolio of capable long-term and short-term suppliers, the Company believes it has increased the security of its gas supply. Potential suppliers are evaluated on a variety of factors including past performance and gas delivery capability.

The second primary area of concern, Mr. Yoho testified, is maintaining the necessary operational flexibility in the Company's gas supply portfolio. Operational flexibility is required because of the daily changes in its market requirements related to the unpredictable nature of weather, the operating schedules of its industrial customers, and their capacity to switch to alternate fuel. Mr. Yoho testified that while each of its gas supply agreements has different purchase commitments and swing capabilities, the Company's gas supply portfolio as a whole must be capable of handling the monthly, daily and hourly changes in market requirements.

The third primary area of emphasis is cost of gas. Mr. Yoho testified that the Company is committed to acquiring the most cost effective supplies of natural gas available for its customers while maintaining the necessary security and flexibility to serve their needs.

Mr. Yoho testified that the greatest challenges confronting the Company involve long-term decisions that must be made today which affect Public Service and its customers for many years while facing a future uncertainty of critical factors such as market demand, supply availability, regulation, and legislation. These factors directly affect Public Service's business, Mr. Yoho testified, and are almost certain to change and nearly impossible to predict. Mr. Yoho testified, for example, that the federal regulatory policies which impact the natural gas industry have undergone substantial changes since the late 1970's. Among these changes are the Natural Gas Policy Act of 1978, which began the deregulation of the wellhead prices for natural gas, FERC Orders 380, 436 and 500 series, and finally FERC Orders 636,636-A, and 636-B. Along with these generic federal orders was the FERC approval of a restructuring plan for Transcontinental Gas Pipe Line Corporation (Transco) in FERC Docket CP88-391-004, et al., on June

19, 1991. Mr. Yoho testified that these federal actions have dramatically changed the way the natural gas industry operates and will continue to impact the purchasing practices of the Company.

Mr. Yoho explained that the Company historically purchased the majority of its gas from Transco under tariffs approved by the FERC. The purchase price for this gas included the wellhead price of gas and all transportation and balancing charges to bring the gas from the wellhead to Public Service's city gate. Under current regulations affecting Transco, however, the Company purchases most of its gas directly from producers or marketers in unregulated transactions at either the wellhead or production area pooling points, and Transco transports this gas for Public Service under tariffs approved by the FERC. The Company negotiates the purchase of gas from many possible sources, arranges for the transportation of that gas to Public Service at its delivery points, and manages imbalances when the amount delivered to the receipt points and the amount taken at the delivery points do not match. These activities are now common for Public Service and the other LDCs. Even though a number of these activities now seem routine, Public Service remains concerned about having to make long term purchase decisions when the final FERC regulations are currently unknown.

Mr. Yoho testified that although the Company had made some short term acquisitions through pipelines other than Transco, the Company does not currently purchase gas through other pipelines on a long-term basis. However, Public Service does plan to commence a long-term service with CNG Transmission Corporation on November 1, 1993.

In addition, Mr. Yoho testified that Public Service has taken the following steps to keep its gas costs as low as reasonably possible while accomplishing its stated policies and maintain security of supply and delivery flexibility:

(1) The Company is activity participating in all matters before the FERC and other governmental agencies where actions by those agencies could reasonably impact Public Service's rates and service to its customers.

(2) Public Service has worked with its industrial customers to transport customer-owned gas. Transportation services permit Public Service to compete with alternate fuels without having to negotiate its regular rate schedules.

(3) Public Service communicates on a daily basis directly with numerous supply sources, along with other industry participants, and actively researches and monitors the industry using a variety of sources including industry trade periodicals.

(4) Public Service has frequent internal discussions concerning gas supply and policy and major purchasing decisions. Included in these discussions are various senior level officers including the Company's CEO.

(5) To meet both the winter season and peak day demands of Public Service's growing firm markets along with its interruptible industrial market during non-peak periods, the Company has contracted for the following additional capacity: an increase in its available capacity on Transco by 5,000 dt/day during the 1992-1993 winter period and 30,000 dt/day of service from CNG Transmission.

GAS - MISCELLANEOUS

With respect to the supply used by Public Service to supply its firm transportation contracts, Mr. Yoho testified that the Company has developed a portfolio gas strategy which includes the execution of long-term supply contracts. Mr. Yoho testified this approach supports the Company's best cost supply strategy. The Company currently has approximately 192,000 dt/day under long-term contracts with five major producers, three interstate pipeline marketing affiliates, and one interstate pipeline. Most of these contracts, Mr. Yoho testified, have provisions which insure that pricing stays market sensitive. Mr. Yoho stated that the Company is confident that its gas supply and capacity portfolio has the flexibility to meet its market requirements in a secure and cost effective manner.

Mr. Hoard testifying for the Public Staff stated that he had studied the Company's customer mix and market profile, peak day responsibility, and annual gas supply requirements. He then compared these requirements with the Company's gas capacity and supply portfolio to ascertain whether the gas purchases properly matched the Company's needs. Finally, he evaluated the prices paid for capacity and supply. Mr. Hoard stated that his investigation showed that the Company's gas costs were prudently incurred during the period of review.

Mr. Hoard explained that in the course of his investigation he reviewed the Company's monthly deferred account reports, its monthly financial and operating reports, the filing requirements information attached to Company witness Barkley's testimony, the Company's long-term gas supply and capacity contracts, and its response to the 40 questions contained in the Public Staff data requests. The Company's responses to the two Public Staff data requests include information such as (1) design day demand estimates and projections, (2) historical and forecasted local duration curves, (3) projected transmission system upgrades, (4) historical and forecasted annual gas needs, (5) projected gas capacity additions, (6) projected gas supply changes, (7) customer mix and customer market profiles, (8) details on a new FT-NT capacity service, and (9) inquiries regarding the Company's gas purchasing philosophy.

At the Hearing, counsel for CUCA did not question the prudence of the gas costs incurred by the Company during the review period.

Based upon the foregoing, the Commission concludes that the gas costs incurred by the Company during the twelve month review period ended March 31, 1993, were reasonable and prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

·Public Service's deferred account balance for sales customers only at March 31, 1993, was $1,649,098 owed to Public Service, and the deferred account balance for all customers was $2,635,558 payable by Public Service to its customers. In his pre-filed direct testimony, Mr. Barkley quantified the rate increment required to collect the balance due from sales customers over the succeeding twelve months and the refund decrement that would be applicable to all customers deferred account. Mr. Barkley indicated, however, that Public Service might request an offsetting rate adjustment under Rider D to its tariff in order to avoid changing billing rates to implement changes of such small magnitude.

At the hearing, the Public Staff recommended that rates not be reduced now because the credit balance owed to customers in Public Service deferred accounts at March 31, 1993, was relatively low by historical standards and can be expected to decrease during the summer season as a result of fixed gas costs undercollections. Also, in view of the changes in interstate pipeline charges expected this fall due to the pending Transco general rate case (FERC Docket RP92-137) and Transco Restructuring (FERC Docket RS 92-86) proceedings, as well as a probable change in the Company's benchmark commodity cost of gas, the Public Staff indicated that it did not believe it appropriate to change the Company's rates at this time. At the hearing, Mr. Barkley expressed the Company's agreement with the Public Staff's recommendation.

Following the hearing, the Public Staff reconsidered its position in this matter and concluded that G.S. 62-133.4(c) is more appropriately interpreted to require that rates be decreased when an overcollection occurs. As a result, the Public Staff requested that it be allowed to change its recommendation. In its motion to amend its recommendation filed September 17, 1993, counsel for the Public Staff indicated its understanding that Public Service is not requesting permission to collect the amount owed to Public Service from its sales customers at this time, and the Public Staff took no issue with that position. Accordingly, the Public Staff now recommends that the Commission decrease rates to sales customers under Rate Schedules 105, 110, 125, 130, 145, and 150 by $.0545 per dekatherm and decrease rates to transportation customers under Rate Schedules 175 and 180 by $.0545 per dekatherm. The Public Staff further recommends that the Commission approve offsetting rate adjustments, as requested in Public Service's prefiled direct testimony, because the credit balance owed to customers in Public Service's deferred accounts at March 31, 1993, was relatively low by historical standards and negative at June 30, 1993.

CUCA filed a post-hearing brief in which it argues that under G.S. 62-133.4(c) the Commission <u>must</u> make rate adjustments in each annual gas cost review proceeding "to recoup any test period underrecovery and to disgorge any test period overrecovery." In making this argument, CUCA stresses that the statute uses the word "shall" as to both the refund of any overrecovery and the recovery of any deficiency. The Commission rejects CUCA's argument. CUCA ignores the words that follow "shall." The statute provides that the Commission shall "require" the utility to refund any overrecovery, but it provides that the Commission shall "permit" the utility to recover any deficiency. The term "require" means to direct, demand or compel while the term "permit" means to allow or consent, to give leave. Black's Law Dictionary 1140 and 1304 (6th ed. 1990). In this proceeding, Public Service has not asked to recover the undercollection in the deferred account for sales only customers, and the statute does not require the Commission to order such. CUCA also reiterates its objections to the use of equal per dekaterm rate changes in proceedings under G.S. 62-133.4. The Commission has rejected CUCA's arguments on this point at least twice, and those decisions will not be disturbed now.

The Commission concludes that it is just and reasonable to order a refund of the deferred account balance for all customers of $2,635,558 in the form of a rate decrement in the amount of $.0545 per dekatherm applicable to Rate Schedules 105, 110, 125, 130, 145, 150, 175 and 180. Simultaneously, the Commission will approve, under the provisions of Commission Rule R1-17(k)(3), an increase in rates to customers under Rate Schedules 105, 110, 125, 130, 145, 150, 175 and 180 of $.0545 per dekatherm.

IT IS, THEREFORE, ORDERED as follows:

1. That Public Service's accounting for gas costs and recoveries during the twelve month period of review ended March 31, 1993, be, and the same hereby is, approved;

2. That the gas costs incurred by Public Service during the twelve month period of review ended March 31, 1993, were reasonable and prudently incurred and Public Service be, and hereby is, authorized to recover its gas costs as provided herein; and

3. That Public Service refund the $2,635,558 deferred account balance for all customers through a decrement of $.0545 per dekatherm under Rate Schedules 105, 110, 125, 130, 145, 150, 175 and 180; and that a simultaneous increase in rates to customers under Rate Schedules 105, 110, 125, 130, 145, 150, 175 and 180 of $.0545 per dekatherm under the provisions of Commission Rule R1-17(k)(3) is hereby approved. These rate changes shall be placed into effect on service rendered on or after the first billing cycle of the month following the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. G-9, SUB 329

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	ORDER ON
Company, Inc., for Annual Review of	)	ANNUAL
Gas Costs Pursuant to G.S. 62-133.4(c)	)	REVIEW OF
and Commission Rule R1-17(k)(6)	)	GAS COSTS

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on October 6, 1992, and December 17, 1992

BEFORE: Commissioner Sarah Lindsay Tate, Presiding, and Commissioners Julius A. Wright and Charles H. Hughes

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

Jerry W. Amos and James H. Jeffries, IV, Brooks, Pierce, McLendon, Humphrey & Leonard, Post Office Box 2600, Greensboro, North Carolina 27420

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28680

For the Attorney General:

Margaret Force, Associate Attorney General, North Carolina Department of Justice, Post Office Box 729, Raleigh, North Carolina 27602

For the Public Staff:

David T. Drooz, Staff Attorney, Public Staff--North Carolina Utilities Commission, Post Office Box 29520, Raleigh North Carolina 27626

BY THE COMMISSION: On July 31, 1992, Piedmont Natural Gas Company, Inc. (Piedmont) filed testimony and exhibits relating to the annual review of its gas costs under G.S. 62-133.4(c) and NCUC Rule R1-17(k)(6). The Commission issued its Order Scheduling Hearing and Requiring Public Notice on August 5, 1992.

A petition to intervene was filed by Carolina Utility Customers Association, Inc. (CUCA) on August 20, 1992, and the petition was granted by the Commission on August 21, 1992. The Attorney General filed a Notice of Intervention on August 21, 1992.

The direct testimony of Ware F. Schiefer and Ann H. Boggs was filed by Piedmont on July 31, 1992. The direct testimony of James G. Hoard and Eugene H. Curtis, Jr., was filed by the Public Staff on September 21, 1992. The supplemental testimony of Eugene H. Curtis, Jr., was filed on September 23, 1992. The rebuttal testimony of Ware F. Schiefer was filed on October 2, 1992. On December 8, 1992, the Public Staff filed "Corrections to the Public Staff's Prefiled Testimony and Exhibits." No other party filed testimony.

When this matter came on for hearing on October 6, 1992, Piedmont called Ann H. Boggs as its first witness. During the cross-examination of Witness Boggs, the Public Staff sought to elicit testimony on the rate of return earned by Piedmont during the review period. Piedmont objected, and the hearing was recessed so that the issues raised by the objections could be more thoroughly briefed. On October 13, 1992, the Public Staff filed its Motion on Scope of Proceeding in which it argued that the Commission should consider Piedmont's rate of return during the review period. Filings in support of the Public Staff's arguments were filed on October 19, 1992 by the Attorney General and on October 21, 1992 by CUCA. On October 21, 1992, Piedmont filed a response and NCNG and Public Service filed amicus curiae comments in opposition to the Public Staff's arguments. On October 22, 1992, the Public Staff filed a reply.

On October 28, 1992, the Commission issued its Order on Scope of Proceeding. In that order, the Commission ruled as follows:

"The Commission never intended to review the earnings of the LDCs in annual gas cost review proceedings. The rate of return actually achieved by an LDC in the test period for its annual gas cost review proceeding is therefore not a relevant issue subject to litigation by direct testimony or cross-examination."

The Commission rescheduled the hearing for November 5, 1992. On October 30, 1992, the Commission again rescheduled the hearing for December 17, 1992. The hearing was reconvened on December 17.

Based on the testimony, exhibits received into evidence, items of judicial notice, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. The period of review in this proceeding is August 1, 1991 through May 31, 1992.

2. During the period of review, Piedmont incurred gas costs of $130,823,032, received $115,127,204 of this amount through rates and the balance of $15,695,828 through a debit to the deferred accounts.

3. At May 31, 1992, Piedmont had a $1,556,309 debit balance in its commodity deferred account and a $571,167 credit balance in its demand deferred account.

4. Piedmont made a correcting journal entry in August and September 1992 to debit cost of gas and credit refund due to the customer by $37,295.

5. Piedmont has properly accounted for its gas costs during the period of review and the correcting journal entry is proper.

6. Piedmont has made prudent gas purchasing decisions, and all of the gas costs incurred by Piedmont during the period of review were prudently incurred.

7. Piedmont should be permitted to recover 100% of its prudently incurred gas costs incurred during the period of review in the manner set forth in decretal paragraph 5.

8. Pursuant to a protective order issued by the Commission in Docket G-100, Sub 47, access to Piedmont's gas contracts is subject to the following terms and conditions: (a) access is limited to those employees of the Public Staff and Attorney General who have executed a specified Nondisclosure Certificate, (b) access is limited to the Raleigh office of Piedmont's attorneys, and (c) the reviewing parties may not reproduce the contracts but may make handwritten notes of the same; however, these notes are to be destroyed within 30 days after each general rate case.

9. Access to a local distribution company's gas contracts is a generic matter affecting all natural gas public utilities, not just Piedmont. The Commission will issue a separate order in Docket No. G-100, Sub 47, for the purpose of further review of this matter.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

There is no dispute as to the factual matters contained in the Commission's Findings of Fact Nos. 1-5. The only two witnesses to offer testimony on the amount and accounting for these gas costs were witnesses Boggs and Hoard, and they are in agreement as to the amount and the accounting of these costs. Witness Boggs testified that the period of review in this proceeding is August 1, 1991 through May 31, 1992, that during the period of review, Piedmont incurred gas costs of $130,823,032, received $115,127,204 of this amount through rates and the balance of $15,695,828 through a debit to the deferred accounts, that at May 31, 1992, Piedmont had a $1,556,309 debit balance in its commodity deferred account and a $571,167 credit balance in its demand deferred account, and that Piedmont made a correcting journal entry in August and September 1992 to debit cost of gas and credit refund due to the customer by $37,295. Witness Hoard testified that Piedmont has correctly accounted for its gas costs during the period of review with one exception which was corrected by the journal entry in August and September 1992. Although these witnesses were cross-examined by the various parties, such cross-examination did not elicit any evidence to support a finding that the amount and accounting for these costs was not appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

There is also no dispute as to the factual matters contained in the Commission's Finding of Fact No. 6. The only two witnesses to offer testimony on whether Piedmont's gas costs were prudently incurred were witnesses Schiefer and Curtis, and they agree that all of the costs were prudently incurred. Although these witnesses were cross-examined by the various parties, such cross-examination did not elicit any evidence to support a finding that any of Piedmont's gas costs were not prudently incurred.

Witness Schiefer testified that Piedmont purchases gas jointly for North Carolina and South Carolina and that its purchasing policies and practices apply to both states. Under Piedmont's purchasing policy, it considers five interrelated factors--the price of the gas, the security of the gas supply, the flexibility of the gas supply, gas deliverability and supplier relations. Witness Schiefer testified that Piedmont purchases gas from two entirely different sources--the spot market and the long-term market--and sells the gas to two distinct markets--the firm market (principally residential, firm commercial and small firm industrial customers) and the interruptible market (principally large industrial interruptible customers). Witness Schiefer further testified that before entering into any agreement to purchase gas, Piedmont carefully considers the use for the supply and weighs the five interrelated factors. To help Piedmont to exercise the judgment required to weigh these factors, Piedmont keeps informed about all aspects of the natural gas industry, intervenes in all major proceedings affecting its pipeline suppliers, participates in studies designed to help determine the availability and price of gas in the future, subscribes to industry literature which reports past prices and makes predictions of future prices, regularly attends industry seminars, and attempts to determine the prices being paid by other gas purchasers.

Witness Schiefer testified that during the past year, Piedmont has taken the following steps to keep its gas costs as low as possible, consistent with its "best cost" policy: (1) actively participated in all matters before FERC and other governmental agencies where action by those agencies could reasonably be expected to affect Piedmont's rates and services to its customers; (2) worked with its industrial customers to transport customer owned gas, (3) held regular meetings of its internal gas supply committee to review performance, evaluate plans and discuss issues of significance, and (4) contracted for the following additional capacity to serve its market: (a) 60,000 dt/day from Columbia Gas Transmission Corporation to commence with the 1992-1993 winter period, (b) 25,000 dt/day of service on the Niagara Interstate Pipeline project which is expected to be available for the 1992-93 winter, and (c) a transportation project with Texas Gas Transmission Corporation, CNG Transmission Corporation and Transcontinental Gas Pipe Line Corporation to provide Piedmont with approximately 13,000 dt/day of transportation capacity in the Gulf Coast area which is expected to begin in November 1993.

In his direct testimony, Mr. Curtis testified that "the Public Staff has not found any imprudence in Piedmont's gas costs." On cross-examination he testified that "[t]he Public Staff has found Piedmont's gas cost during the ten months ending May 31, 1992, to have been prudently incurred."

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

Rule R1-17(k) provides: "The intent of these rules is to permit LDCs to recover 100% of their prudently incurred gas costs applicable to North Carolina operations." "Gas costs" is defined to include "capacity charges, ...storage charges, ... and any other similar charges in connection with the purchase, storage or transportation of gas for the LDC's system supply."

In its Final Order Adopting Commission Rule R1-17(k), dated April 9, 1992, in Docket No. G-100, Sub 58, the Commission provided the following language regarding the recovery of gas costs.

> "The Commission notes that G.S. 62-133.4 was a part of Chapter 598 of the 1991 Session Laws which was enacted to encourage and facilitate expansion of natural gas service throughout unserved areas in North Carolina. As stated earlier, the LDCs have advocated the recovery of 100% of additional capacity and storage costs and argued that such recovery is consistent with the policy of the state which encourages the LDCs to add new customers and to acquire new gas supplies for those new customers."
>
> "After carefully considering the arguments of the parties in this docket, the filings made in this docket and the record as a whole, the Commission deems it appropriate to reconsider the issue of the recovery of additional capacity and storage costs. Upon reconsideration, the Commission concludes that it is appropriate to allow recovery by the LDCs pursuant to G.S. 62-133.4 of 100% of their prudently incurred costs for additional capacity and storage added subsequent to a general rate case proceeding. In so concluding, the Commission is persuaded that such recovery is more consistent with the intent of Chapter 598 of the 1991 Session Laws and will not serve to discourage the LDCs from obtaining needed additional volumes of gas to

> facilitate the expansion of natural gas service in North Carolina. Furthermore, the Commission is of the opinion that its conclusion herein will serve to increase the flexibility needed by the LDCs in negotiating the purchase of additional gas supplies and purchasing gas incrementally as needed. Also, as stated in our earlier Order, the Commission is not persuaded that the recovery of additional capacity and storage costs will automatically result in excess returns due to increased expenses and the new investment in plant to be incurred to serve new customers. However, the Commission will carefully monitor the impact of this decision and, should it determine that further action is required, such action will be undertaken in a manner which the Commission considers to be appropriate."

Witness Curtis has identified $2,878,969 of gas costs which he contends should be disallowed. He testified that since Piedmont has not incurred these added capacity and storage charges to expand into unserved territories, it is not appropriate for these charges to be recovered outside the context of a general rate case.

In support of its position, the Public Staff has argued that (1) G.S. 62-133.4 was enacted as part of the legislative intent to promote expansion of natural gas service into unserved areas; (2) Commission Rule R1-17(k) was promulgated to implement G.S. 62-133.4 consistent with the legislative intent; (3) the LDCs maintained that recovery of added capacity and storage costs was appropriate because it would facilitate expansion; (4) the Commission authorized 100% recovery of added capacity and storage charges on the premise that they would be used to promote expansion; and (5) Piedmont in fact did not use the added capacity and storage it purchased in the review period to expand service to unserved areas.

The Attorney General, in his Brief filed with the Commission, supports the Public Staff's position that Piedmont should not be allowed to recover the cost of added capacity and storage in this proceeding. However, the Attorney General would support reopening the rulemaking in Docket No. G-100, Sub 58, if the Commission determines that this is a more appropriate forum to address this issue.

CUCA, in its Brief, cited language in the Commission's Final Order in Docket No. G-100, Sub 58 wherein it stated that it would carefully monitor the impact of its decision and undertake further action if appropriate. Accordingly, CUCA recommended that Docket No. G-100, Sub 58, be reopened for the purpose of reconsidering the additional capacity issue.

Witness Schiefer testified that, in his opinion, the Public Staff's recommendation should be denied because (1) it is contrary to the express language of Rule R1-17(k) and, therefore, amounts to a collateral attack on that rule, (2) as recognized by the Commission in its order permitting 100% recovery of additional capacity and storage costs, Piedmont and the other LDCs need the flexibility provided by 100% recovery to negotiate the purchase of additional gas supplies and to purchase gas incrementally as needed, (3) no clear definition of "unserved territory" presently exists, and, therefore, Piedmont and the other LDCs would have had no way of knowing during the review period whether specific costs would qualify for recovery under the Public Staff's proposal, (4) Piedmont purchases gas for its entire system and not for individual projects, therefore, it is not possible to differentiate between those gas costs which are purchased for "unserved areas" and those which are not, (5) any retroactive change in the Commission's rule would have an adverse effect on Piedmont's stock prices and its ability to raise capital in the future, and (6) the Public Staff's proposal would place the LDCs in a "Catch 22" situation because in a marginal project that would qualify for expansion funds only if gas costs were excluded, the project would qualify for expansion funds; however, once it qualifies for the expansion funds, it would also qualify for recovery of gas costs, at which point, the project would no longer qualify for the expansion funds. Witness Schiefer also testified that Piedmont is recognized as one of the fastest growing gas utilities in the country, that it needed the additional capacity to serve this market and that Piedmont would not have been prudent if it had not obtained the additional capacity at issue in this case. Finally, Witness Schiefer testified that he disagrees that all of the costs identified by Witness Curtis are for "additional capacity."

The Commission has carefully considered the evidence, the arguments of the parties and the record as a whole and concludes that Piedmont should be permitted to recover 100% of its gas costs.

G.S. 62-133.4 permits the Commission to define gas costs. The Commission defined gas costs in Rule R1-17(k) to include the very same kind of capacity costs that the Public Staff now asks the Commission to exclude. In the April 9, 1992, Order, the Commission concluded that it is appropriate to allow recovery by the LDCs pursuant to G.S. 62-133.4 of 100% of their prudently incurred costs for additional capacity and storage added subsequent to a general rate case proceeding. In so concluding, the Commission cited several factors in support of such decision, one of which was that such recovery is more consistent with the intent of Chapter 598 of the 1991 Session Laws and would not serve to discourage the LDCs from obtaining needed additional volumes of gas to facilitate the expansion of natural gas service in North Carolina. Other factors cited were that its decision would serve to increase the flexibility needed by the LDCs in negotiating the purchase of additional gas supplies and purchasing gas incrementally as needed. Nothing in said Order, G.S. 62-133.4, or Rule R1-17(k) provides that the allowed recovery of costs incurred for additional capacity and storage is specifically contingent upon a showing of service to previously unserved areas. The level of service to previously unserved areas is not crucial, in and of itself, to recovery of gas costs in this proceeding. The Commission reiterates that it will monitor the impact of its April 9, 1992 decision to allow 100% of an LDC's prudently incurred costs for additional capacity and storage.

Witness Boggs proposed to recover the $985,142 debit balance in Piedmont's deferred account in the following manner: Effective on the first billing cycle of the month following the date of this Order, Piedmont would recover the commodity deficit by increasing rates to the sales customers purchasing gas under Rates 101, 102, 103 and 104 by $.0319 per dt. Piedmont would refund the credit balance in its demand deferred account by reducing rates to its sales customers purchasing gas under Rates 101, 102, 103 and 104 and its transportation customers transporting gas under Rate Schedules 113 and 114 by $.0098 per dt. The net effect of the foregoing action is an increase in rates to sales customers of $.0221 per dt. and a decrease in rates to transportation customers of $.0098 per dt. Simultaneous with the above action, Piedmont would decrease rates to sales customers purchasing gas under Rates 101, 102, 103 and 104 by \$.0319 per dt. under the provisions of Rule R1-17(k)(3)(ii) and increase rates to sales customers purchasing gas under Rates 101, 102, 103 and 104 and to transportation customers transporting gas under Rate Schedules 113 and 114 by \$.0098 per dt. under the provisions of Rule R1-17(k)(3)(i). The effect of these last two changes is to offset exactly the changes to rates resulting from the annual true-up. No party offered any opposition to this proposal, and the Commissions finds and concludes that it is fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 AND 9

Witness Hoard testified that the protective order adopted by the Commission in Docket No. G-100, Sub 47 makes access to Piedmont's gas contracts subject to the following terms and conditions: (a) access is limited to those employees of the Public Staff and Attorney General who have executed a specified Nondisclosure Certificate, (b) access is limited to the Raleigh office of Piedmont's attorneys, and (c) the reviewing parties may not reproduce the contracts but may make handwritten notes of the same. Witness Hoard recommends that these procedures be amended and that Piedmont be required to file its contracts with the Public Staff with the name of the service-provider and the specified dollar price "whited-out." He testified that the present procedures make it difficult for the Public Staff to review Piedmont's contracts thoroughly. Witness Hoard also recommended that the requirement that it destroy its notes pertaining to the contracts within 30 days of each general rate case be eliminated.

Witness Schiefer testified that Piedmont recognizes the right of the Public Staff to review Piedmont's gas supply contracts, and that Piedmont's only concern is that these contracts not be subject to examination by parties who either wish to sell gas to Piedmont or wish to compete with Piedmont for the purchase of gas. He testified that on several occasions Piedmont has offered to provide the contracts to the Public Staff if the Public Staff could assure Piedmont that the contracts will not be subject to the Public Records Act, but that the Public Staff had stated that it was unable to do so. Witness Schiefer also testified that as a result of Order No. 636, there is more competition for gas supplies now than ever before and, therefore, more need to keep the information confidential. Witness Schiefer objected to the proposal to "white-out" the name of the service-provider and the price, stating that there were many other important provisions of these contracts that need to be kept confidential. Witness Schiefer further testified that he believes that the existing procedures provide the best compromise for the provision of information to the Public Staff and the protection of that information from those persons who would use it to the disadvantage of Piedmont and its customers.

The Attorney General, in his Brief, supports the position of the Public Staff in this regard. CUCA, in its Brief, argues that the enactment of G.S. 62-133.4 compels a modification of the Commission's confidentiality rules to permit all intervenors adequate access to the information necessary to litigate the prudence issue and, accordingly, modification to the confidentiality rules promulgated in Docket No. G-100, Sub 47, is necessary.

The Commission recognizes that the present procedures were established prior to the enactment of G.S. 62-133.4(c) and the adoption of Commission Rule R1-17(k). Prudence reviews will now be addressed annually for each LDC. The changes brought about by this new legislation will result in greater gas cost review responsibilities for the Commission. With these changes, the Commission is of the opinion that it is beneficial to review the procedures for access to gas purchase contracts in a generic proceeding.

Since this matter affects all natural gas utilities, not just Piedmont, the Commission will issue a separate order in Docket No. G-100, Sub 47, in the near future to address this matter further.

IT IS, THEREFORE, ORDERED as follows:

1. That the $130,823,032 of gas costs incurred by Piedmont during the period of review be, and they hereby are, determined to be prudently incurred.

2. That Piedmont's accounting for all such gas costs as set forth in this order be, and the same hereby is, approved.

3. That Piedmont be, and it hereby is, authorized to recover 100% of its prudently incurred gas costs during the period of review, including, but not limited to, 100% of the costs identified by the Public Staff as additional capacity and storage costs.

4. That the Commission will issue a separate order in Docket No. G-100, Sub 47, in the near future to address further the procedures for access to gas purchase contracts of the local distribution companies.

5. That Piedmont be, and it hereby is, permitted to recover the $985,142 debit balance in its deferred account in the following manner: Effective on the first billing cycle of the month following the date of this order, Piedmont shall recover the commodity deficit by increasing rates to the sales customers purchasing gas under Rates 101, 102, 103 and 104 by $.0319 per dt. Piedmont shall refund the credit balance in its demand deferred account by reducing rates to its sales customers purchasing gas under Rates 101, 102, 103 and 104 and its transportation customers transporting gas under Rate Schedules 113 and 114 by $.0098 per dt. The net effect of the foregoing action is an increase in rates to sales customers of $.0221 per dt. and a decrease in rates to transportation customers of $.0098 per dt. Simultaneous with the above action, Piedmont shall decrease rates to sales customers purchasing gas under Rates 101, 102, 103 and 104 by $.0319 per dt. under the provisions of Rule R1-17(k)(3)(ii) and increase rates to sales customers purchasing gas under Rates 101, 102, 103 and 104 and to transportation customers transporting gas under Rate Schedules 113 and 114 by $.0098 per dt. under the provisions of Rule R1-17(k)(3)(i). The effect of these last two changes is to offset exactly the changes to rates resulting from the annual true-up.

6. That appropriate tariffs shall be filed by Piedmont within ten days of the date of this Order.

7. That Piedmont shall send notice to all its customers of the rate changes approved herein by appropriate bill inserts in the first billing cycle of the month following the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-9, SUB 339

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Wednesday, October 6, 1993, in the Commission Hearing Room, Dobbs Building, Raleigh, North Carolina

BEFORE: Commissioner Laurence A. Cobb, Presiding; Commissioner William W. Redman; and Commissioner Ralph A. Hunt

APPEARANCES:

For the Applicant:

Jerry W. Amos, Brooks, Pierce, McLendon, Humphrey & Leonard, L.L.P., Post Office Box 26000, Greensboro, North Carolina 27420

For the Public Staff:

Paul L. Lassiter, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, Jr., Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28680-1269

BY THE COMMISSION: On August 2, 1993, Piedmont Natural Gas Company, Inc. (Piedmont or the Company) filed the direct testimony and exhibits of Ware F. Schiefer, Senior Vice President of Piedmont, and Ann H. Boggs, Manager of Gas Accounting of Piedmont, in connection with the annual prudence review required by G.S. 62-133.4 and Commission Rule R1-17(k)(6).

On August 3, 1993, the Commission scheduled a public hearing and required public notice. On August 11, 1993, the Commission issued an order rescheduling the hearing for October 6, 1993.

A petition to intervene filed by the CUCA on August 18, 1993, was allowed by the Commission by order dated August 19, 1993.

The direct testimony of Windley E. Henry and Eugene H. Curtis, Jr., was filed by the Public Staff on September 20, 1993. No other party filed testimony.

Based on the testimony, exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a public utility as that term is defined in Chapter 62 of the North Carolina General Statutes.

2. Piedmont is a local distribution company primarily engaged in the purchase, distribution and sale of natural gas to more than 450,000 customers in the Piedmont region on North Carolina and South Carolina and the metropolitan area of Nashville, Tennessee.

3. Piedmont has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of that Rule.

4. The period of review in this proceeding is the twelve months ended May 31, 1993.

5. During the period of review, Piedmont incurred gas costs of $192,610,777 and received $199,630,942 of this amount through rates. The balance of $7,020,165 was recorded as a credit to the deferred accounts.

6. At May 31, 1993, Piedmont had a credit balance of $6,035,023 in its deferred accounts. The $6,035,023 credit balance is the sum of a $226,212 credit balance to the commodity deferred account and a $5,808,811 credit balance to the demand deferred account.

7. The Public Staff took no exceptions to the Company's accounting for gas costs and recoveries during the period in question.

8. Piedmont has properly accounted for its gas costs and collections from customers during the period of review.

9. Piedmont makes its gas purchasing decisions pursuant to what it refers to as a "best cost gas purchasing policy," which considers the price of the gas, the security of the gas supply, the flexibility of the gas supply, gas deliverability and supplier relations.

10. Piedmont has made prudent gas purchasing decisions, and all of the gas costs incurred by Piedmont during the period of review were prudently incurred.

11. Piedmont should be permitted to recover 100% of its prudently incurred gas costs incurred during the period of review.

12. Piedmont should implement a rate decrement of $.0699 per dt. to all sales customers and a rate decrement of $.0994 per dt. to all transportation customers in order to refund the balances in the deferred accounts for a 12-month period beginning 30 days from the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence for these findings of fact is contained in the official files and records of the Commission and in the testimony of Piedmont witnesses Schiefer and Boggs. These findings are essentially informational, procedural or jurisdictional in nature and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence for these findings of fact is contained in the testimony of Piedmont witnesses Schiefer and Boggs and are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 and Rule R1-17(k)(6) requires local gas distribution companies to submit to the Commission certain information and data for an historical test period, provides for the filing of testimony and exhibits, establishes hearing dates, and provides for notice of such hearings. Piedmont's test period ends May 31, its date for the filing of testimony, exhibits and other information is on or before August 1 of each year and its annual hearing is scheduled for the first Tuesday of October of each year. A review of the record in this docket and of the testimony of Piedmont witnesses Schiefer and Boggs shows that Piedmont complied with the statute and the Commission's rule.

Witness Boggs testified that Piedmont filed the required monthly information with Commission and provided copies of such filings to the Public Staff. Witness Boggs filed ten schedules with her testimony consisting of a summary of cost of gas expense, demand and storage costs, commodity gas costs, other cost of gas charges/(credits), demand and storage charges, demand and storage capacity level changes, demand and storage costs incurred versus collected, deferred account activity - sales customers only account, deferred account activity - all customers account, and gas supply.

No party has offered any evidence that Piedmont did not fully comply with the procedural and filing requirements of the statute and the rule.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

There is no dispute as to the factual matters contained in the Commission's Findings of Fact Nos. 5-8. The only two witnesses to offer testimony on the amount and accounting for these gas costs were witnesses Boggs and Henry, and they are in agreement as to the amount and the accounting of these costs. Witness Boggs testified that during the period of review, Piedmont incurred gas costs of $192,610,777, received $199,630,942 of this amount through rates, and that the balance of $7,020,165 was recorded as a credit to the deferred accounts. Witness Boggs further testified that at May 31, 1993, Piedmont had a credit balance of $6,035,023 in its deferred accounts, which balance is the sum of a

$226,212 credit balance in the commodity deferred account and a $5,808,811 credit balance in the demand deferred account. Public Staff witness Henry testified that the Company has properly accounted for its gas costs during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

There is also no dispute as to the factual matters contained in the Commission's Findings of Fact Nos. 9-11. The only two witnesses to offer testimony on whether Piedmont's gas costs were prudently incurred were witnesses Schiefer and Curtis, and they agree that all of the costs were prudently incurred. Although these witnesses were cross-examined by the various parties, such cross-examination did not elicit any evidence to support a finding that any of Piedmont's gas costs were not prudently incurred.

Witness Schiefer testified that Piedmont purchases gas jointly for North Carolina and South Carolina and that its purchasing policies and practices apply to both states. Under Piedmont's purchasing policy, it considers five interrelated factors--the price of the gas, the security of the gas supply, the flexibility of the gas supply, gas deliverability and supplier relations. Witness Schiefer testified that Piedmont purchases gas from two entirely different sources--the spot market and the long-term market--and sells the gas to two distinct markets--the firm market (principally residential, firm commercial and small firm industrial customers) and the interruptible market (principally large industrial interruptible customers). Witness Schiefer further testified that before entering into any agreement to purchase gas, Piedmont carefully considers the use for the supply and weighs the five interrelated factors. To help Piedmont to exercise the judgment required to weigh these factors, Piedmont keeps informed about all aspects of the natural gas industry, intervenes in all major proceedings affecting its pipeline suppliers, participates in studies designed to help determine the availability and price of gas in the future, subscribes to industry literature which reports past prices and makes predictions of future prices, regularly attends industry seminars, and attempts to determine the prices being paid by other gas purchasers.

Witness Schiefer testified that during the review period, Piedmont has taken the following steps to keep its gas costs as low as possible, consistent with its "best cost" policy: (1) actively participated in all matters before FERC and other governmental agencies where action by those agencies could reasonably be expected to affect Piedmont's rates and services to its customers, (2) worked with its industrial customers to transport customer owned gas, (3) held regular meetings of its internal gas supply committee to review performance, evaluate plans and discuss issues of significance, (4) begun receiving 60,000 dt./day from Columbia Gas Transmission Corporation, (5) continued to utilize the flexibility available within its gas contracts to purchase and dispatch gas in the most cost effective manner by balancing high dependability and low purchase obligations and by purchasing gas on the spot market when it made economic sense to do so, and (6) actively sought load growth from "year around" markets which tends to decrease the average cost of gas.

In his direct testimony, Mr. Curtis testified that he had reviewed the matters relating to the prudence of Piedmont's gas purchases and concluded that all gas costs during the review period were prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

Witness Boggs proposed in her prefiled testimony to refund the $6,035,023 credit balance in Piedmont's deferred accounts in the following manner: Effective on the first billing cycle of the month following the date of this order, Piedmont would refund the commodity deferred account credit balance by decreasing rates by $.0046 per dt. to the sales customers purchasing gas under Rates 101, 102, 103 and 104. Piedmont would refund the credit balance in its demand deferred account by reducing rates by $.0994 per dt. to its sales customers purchasing gas under Rates 101, 102, 103 and 104 and its transportation customers transporting gas under Rate Schedules 113 and 114. The net effect of these two rate reductions is a decrease in rates to sales customers of $.1040 per dt. and a decrease in rates to transportation customers of $.0994 per dt. Simultaneous with the above action, Piedmont would increase rates to sales customers purchasing gas under Rates 101, 102, 103 and 104 by $.0046 per dt. under the provisions of Rule R1-17(k)(3)(ii) and increase rates to sales customers purchasing gas under Rates 101, 102, 103 and 104 and to transportation customers transporting gas under Rate Schedules 113 and 114 by $.0994 per dt. under the provisions of Rule R1-17(k)(3)(i). The effect of these last two changes is to offset exactly the changes to rates resulting from the annual true-up and to avoid any changes in rates at this time.

Public Staff witness Curtis proposed two changes to Piedmont's refund proposals. First, he testified that the rate reductions should be reduced to remove $1,662,007 which Piedmont has proposed to return to the Expansion Fund Escrow Account in Docket No. G-9, Sub 332. Second, he testified that the Public Staff objects to Piedmont's proposal to implement an offset in this proceeding. He testified that the balances in the deferred accounts are significant and that they should be refunded as contemplated by G.S. 62-133.4(c).

Company witness Boggs testified that Piedmont does not object to the Public Staff's proposal to reduce the rate reduction provided the Commission approves Piedmont's proposal to return the $1,662,007 to the Expansion Fund Escrow Account in Docket No. G-9, Sub 332. Witness Boggs also testified that Piedmont does not object to seeking any offset in a separate proceeding.

On October 7, 1993, the Public Staff filed a late-filed exhibit to correct the amount of reduction in rates under its proposal to $.0699 per dt. for sales customers and to $.0994 per dt. for transportation customers.

On December 21, 1993, the Commission issued an order in Docket No. G-9, Sub 332, approving the return of $1,662,007 to the Expansion Fund Escrow Account. On its own motion, the Commission takes judicial notice of this order.

G.S. 62-133.4(c) provides for annual review proceedings such as this one to compare the utility's prudently-incurred gas costs with gas costs recovered from the utility's customers. The statute provides that the Commission "shall, subject to G.S. 62-158, require the utility to refund any overrecovery by credit to bill or through a decrement in its rates. . . " (emphasis added). In Piedmont's last annual review, the rate changes required by G.S. 62-133.4(c) were relatively small. Piedmont proposed corresponding simultaneous offsets to avoid changing rates, no other party objected, and the Commission ordered it. In this proceeding, witness Boggs again proposed that simultaneous offsets be approved. Witness Curtis objected. He explained that since the overcollection in this proceeding is a significant amount, the Public Staff recommends that the refunds contemplated by G.S. 62-133.4(c) be made without an offset. He testified that if Piedmont wishes to file for a rate adjustment in a separate proceeding, the Public Staff "would certainly take a look at that and make an appropriate recommendation at that point and time." In its brief, CUCA argues that the Commission should "balance the considerations for and against the implementation of offsetting rates and adjustments in light of all of the surrounding facts and circumstances." In this proceeding, CUCA feels that the "size of these overrecoveries and the general upward tendency in Piedmont's rates militate strongly against negating the resulting rate decrements with offsetting increments."

The Commission agrees with the Public Staff that G.S. 62-133.4(c) requires the Commission to refund overrecoveries of gas costs. In the last Piedmont annual review, the Commission ordered rate changes but offset them with corresponding simultaneous offsets. The Commission believes that that decision was appropriate because the amount of money involved was relatively small and no party objected. However, we do not believe such an offset to be appropriate in this proceeding. Such an offset would simply negate the refunds required by G.S. 62-133.4(c). The refunds required in this proceeding are significant in amount. Further, there is no provision in either G.S. 62-133.4 or our Rule R1-17(k) providing for such a simultaneous offset. The Rule makes detailed provisions for rate adjustments relating to gas costs and the deferred accounts, and the Commission believes that any rate adjustment should be based on a filing made pursuant to that Rule. Since we are reaching a different decision than the one in Piedmont's last annual review, the Commission will delay the present refunds for 30 days. Piedmont may, if it chooses, decide to seek some rate adjustment during this 30-day period. However, any such filing must comply with the requirements of Rule R1-17(k), and it will be decided on the basis of that Rule.

Based on the evidence and conclusions above, the Commission concludes that Piedmont should reduce its rates by the amounts set forth in decretal paragraph 4 for a 12-month period beginning 30 days from the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the $192,610,777 of gas costs incurred by Piedmont during the period of review be, and they hereby are, determined to be prudently incurred.

2. That Piedmont's accounting for all such gas costs as set forth in this order be, and the same hereby is, approved.

3. That Piedmont be, and it hereby is, authorized to recover 100% of all of its prudently incurred gas costs during the period of review.

4. That Piedmont be, and it hereby is, directed to reduce its rates to all sales customers purchasing gas under Rates 101, 102, 103 and 104 by $.0699 per

dt. and to all transportation customers transporting gas under Rate Schedules 113 and 114 by $.0994 per dt. effective 30 days from the date of this Order and continuing for 12 months.

ISSUED BY ORDER OF THE COMMISSION
This the 23rd day of December 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-21, SUB 306
DOCKET NO. G-21, SUB 307

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by North Carolina Natural Gas Corporation for the Establishment of an Expansion Fund and Approval of Initial Funding and In the Matter of Petition by North Carolina Natural Gas Corporation for Approval of the Use of Expansion Funds for a Certain Project	) ORDER ESTABLISHING EXPANSION FUND AND APPROVING INITIAL FUNDING IN DOCKET NO. G-21, SUB 306, AND DEFERRING ACTION ON PROJECT APPROVAL IN DOCKET NO. G-21, SUB 307

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, Tuesday, September 22, 1992, at 9:30 a.m. and Tuesday, October 27, 1992, at 9:30 a.m. through Wednesday, October 28, 1992.

BEFORE: Commissioner Laurence A. Cobb, Presiding; Chairman William W. Redman, Jr., Commissioners Sarah Lindsay Tate, Robert O. Wells, Julius A. Wright, Charles H. Hughes and Allyson K. Duncan

APPEARANCES:

For North Carolina Natural Gas Corporation:

Donald W. McCoy and Jeffrey N. Surles, Attorneys at Law, McCoy, Weaver, Wiggins, Cleveland & Raper, Post Office Box 2129, Fayetteville, North Carolina 28302

For the Using and Consuming Public:

Gisele L. Rankin, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

Margaret Force, Associate Attorney General, Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, Post Office Drawer 1269, Morganton, North Carolina 28655

For Aluminum Company of America:

M. Toler Workman, Attorney at Law, LeBoeuf, Lamb, Leiby, & MacRae, 2840 Plaza Place, Suite 400, Raleigh, North Carolina 27612

For Federal Paper Board Company, Inc., and Cape Industries, Inc.:

Ralph McDonald and Cathleen M. Plaut, Attorneys at Law, Bailey & Dixon, Post Office Box 1351, Raleigh, North Carolina 27602-1351

For the Cities of Greenville, Monroe, Rocky Mount, Wilson and the Greenville Utilities Commission:

Nancy Bentson Essex, Attorney at Law, Poyner & Spruill, Post Office Box 10096, Raleigh, North Carolina 27605

For the Public Works Commission of the City of Fayetteville:

Marland C. Reid and Rebecca F. Person, Attorneys at Law, Reid, Lewis, Deese & Nance, Post Office Drawer 1358, Fayetteville, North Carolina 28302

For Libbey-Owens-Ford Company:

James P. Cain, Attorney at Law, Petree, Stockton, 4101 Lake Boone Trail, Post Office Box 300004, Raleigh, North Carolina 27622

BY THE COMMISSION: On July 8, 1992, the General Assembly of North Carolina enacted G.S. 62-158, which authorizes the North Carolina Utilities Commission (Commission) to order that a natural gas utility create a special natural gas expansion fund to be used by that company to construct natural gas facilities in areas of its franchised territory that otherwise would not be feasible. It further enacted G.S. 62-2(9), which declares it to be the policy of the State to facilitate the construction of facilities in and the extension of natural gas service to unserved areas in order to promote the public welfare throughout the State.

G.S. 62-158(d) provides for the Commission to implement the statute by adopting rules for the establishment of expansion funds, for the use of such funds, for the remittance to the expansion fund or to customers of supplier and transporter refunds and expansion surcharges or other funds that were sources of the expansion fund, and for appropriate accounting, reporting and ratemaking treatment. By Order dated April 9, 1992, the Commission adopted Rules R6-81 through R6-88 for these purposes.

On May 13, 1992, North Carolina Natural Gas Corporation (NCNG) filed a Petition with the Commission in Docket No. G-21, Sub 306, seeking the establishment of an expansion fund and approval of initial funding. NCNG also requested approval to use money from the expansion fund for a certain project involving the extension of natural gas service through southern Wayne County and into Duplin County.

By Motion dated May 20, 1992, the Public Staff sought to have NCNG refile its request for project approval in a separate docket. On May 26, 1992, NCNG agreed to refile if the Commission deemed it appropriate, but asked that the matters be consolidated for hearing. On June 9, 1992, the Commission issued an Order requiring NCNG to refile its request for project approval in a separate docket, consolidating the matters for hearing, scheduling public hearings for September 22, 1992, setting dates for prefiled testimony and ordering NCNG to mail to its customers and publish public notice.

On July 13, 1992, NCNG filed a Petition in Docket No. G-21, Sub 307, seeking approval of the use of expansion funds for a project to extend gas service through southern Wayne County and into Duplin County including the unserved towns of Mount Olive and Faison.

Petitions to intervene were made and allowed for the following parties: Carolina Utility Customers Association, Inc. (CUCA); the Public Works Commission of the City of Fayetteville (PWC); the Aluminum Company of America (Alcoa); Federal Paper Board Company, Inc., and Cape Industries, Inc.; the Cities of Monroe, Rocky Mount, Wilson, Greenville and the Greenville Utilities Commission (Cities); and Libbey-Owens-Ford Company (LOF). The Public Staff and the Attorney General also intervened.

Upon motion of several parties for a continuance, the Commission, by Order dated August 19, 1992, ordered that the September 22, 1992 hearing be for the limited purpose of receiving testimony from public witnesses and that the hearing reconvene on October 27, 1992.

On September 17, 1992, NCNG filed a Supplemental Request for Approval of Funding in the Sub 306 docket, requesting that additional supplier refunds be included in any expansion fund established by the Commission, bringing the total amount of supplier refunds at issue to $3,713,822 plus interest. The Commission issued an Order on September 25, 1992, providing for the Supplemental Request to be considered at the October 27 hearing and requiring NCNG to provide public notice.

Also on September 17, 1992, CUCA filed a Motion to Dismiss NCNG's Petitions in these dockets on the grounds that G.S. 62-158 is unconstitutional. NCNG responded on September 30, 1992, and CUCA replied to that response on October 12, 1992. At the September 22, 1992 hearing CUCA stated that it did not need to be heard on its Motion. At the October 27, 1992 hearing, the Commission ruled that the CUCA Motion to Dismiss would be taken under advisement and that parties could address it in briefs and proposed orders.

The following witnesses appeared and testified on September 22, 1992: Randy Harrell, Executive Director, Industrial Development Commission, Elizabeth City, Pasquotank County; Betsy H. Johnson, Chairman, Wayne County Board of Commissioners; John C. Howard, Executive Director, Wayne County Economic Development Commission; Louis M. Pate, Jr., Mayor of Mount Olive; Bill Wall, Chairman, Community Development Committee, Eastern North Carolina Chamber of Commerce; Woody Brinson, Executive Director, Duplin County Economic Development

Commission; Vance Alphin, Duplin County Commissioner; Kenneth Gore, Manager, North Carolina Hydraulic Manufacturing, Beulaville, Duplin County; Arnold Duncan, Administrative Manager, Stevcoknit Fabrics Company, Wallace, Duplin County; Earl Stephenson, Northampton County Economic Development Commission; Mary Lilley, Executive Director, Martin County Economic Development Commission; Bob Spivey, Executive Director, Bertie County Economic Development Commission; David Joyner, Bertie County Commissioner; Jeff Newsome, Executive Director, Onslow County Economic Development Commission; and Wayne Zeigler, Executive Director, Wilmington Industrial Development, Inc., appearing on behalf of Pender County.

The parties presented their witnesses beginning in Raleigh on October 27, 1992. NCNG presented the testimony and exhibits of Calvin B. Wells, President and Chief Executive Officer of NCNG; Terrence D. Davis, Vice-President - Industrial Marketing and Liquified Natural Gas Plant; and Robert P. Evans, Manager - Statistical Services.

The following intervenors presented witnesses. Alcoa presented the testimony of Maynard F. Stickney, a consultant for Alcoa. PWC presented the testimony and exhibits of Steven K. Blanchard, Director of Generation and Power Supply for PWC. CUCA presented the testimony of J. Bertram Solomon of Marietta, Georgia, a consultant hired by CUCA. Federal Paper presented the testimony of Paul W. Magnabosco, Director of Energy for Federal Paper. Cape Industries presented the testimony of Louis E. Lee, Utilities Department Supervisor for Cape Industries. LOF presented the testimony of Mark R. Frye, Production Purchases Manager for LOF. The Cities presented the testimony of William H. Batchelor, Rocky Mount City Manager; Jerry Edward Cox, Monroe City Manager; Charles Wilson Whitley, Jr., Director of Utilities for the City of Wilson; Malcolm A. Green, General Manager for the Greenville Utilities Commission and Kevin W. O'Donnell, a consultant for the Cities.

The Public Staff presented the testimony of George Sessoms, Public Utilities Financial Analyst and Director of the Economic Research Division of the Public Staff and James G. Hoard, Supervisor of the Natural Gas Section in the Accounting Division of the Public Staff.

On November 16, 1992, the Commission issued an Order inviting interested persons to file amicus curiae briefs addressing the issues raised by the Motion to Dismiss filed by CUCA. Amicus curiae briefs were subsequently filed by Piedmont Natural Gas Company, Inc.; Public Service Company of North Carolina, Inc.; and the Process Gas Consumers Group.

Based on NCNG's Petitions, the testimony and exhibits offered at the hearings, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. NCNG is duly organized as a corporation under the laws of the State of Delaware and is duly authorized to do business in the State of North Carolina. Its principal office and place of business is in Fayetteville, North Carolina.

2. NCNG is a public utility engaged in the business of operating natural gas transmission lines, distribution lines, and other facilities for furnishing and delivering natural gas to the public in its franchised territory in North

Carolina, pursuant to a Certificate of Public Convenience and Necessity granted by this Commission on December 7, 1955, as amended on March 29, 1959, and September 14, 1967.

3. CUCA has filed a Motion asking the Commission to dismiss NCNG's Petitions in these dockets on grounds that G.S. 62-158 is unconstitutional under various provisions of the State and Federal Constitutions. The Commission does not have authority to rule on the constitutionality of a statute that it is charged with implementing. The constitutional issues raised by the Motion should be reserved for the appellate courts.

4. In petitioning for the establishment of an expansion fund in the Sub 306 docket, NCNG has complied with the procedural requirements of G.S. 62-158 and Commission Rule R6-82.

5. There are large areas in NCNG's franchised territory that presently do not have natural gas service and to which expansion of natural gas facilities is economically infeasible. Fourteen of the 43 counties in NCNG's franchised territory have no natural gas service.

6. NCNG is unable to fund expansion projects into these unserved areas using traditional financing methods such as contributions in aid of construction, debt, equity financing and retained earnings.

7. The General Assembly has made the policy decision that it is necessary and in the public interest to authorize special funding methods, including the use of supplier refunds and customer surcharges, to facilitate the construction of facilities and the extension of natural gas service into unserved areas of the State where it would not be economically feasible to expand with traditional methods in order to provide infrastructure to aid industrial recruitment and economic development.

8. The establishment of an expansion fund for NCNG for the purpose of constructing lines into unserved areas in NCNG's territory that are otherwise infeasible to serve in order to provide infrastructure to aid industrial recruitment and economic development is consistent with G.S. 62-2(9) and G.S. 62-158 and is in the public interest.

9. The availability of natural gas service is an important factor in industrial recruitment. Some of the unserved areas in NCNG's franchised territory have lost industrial prospects because they do not have natural gas service available.

10. There is a reasonable prospect that the expansion of natural gas facilities into unserved areas by use of expansion funds will assist in the economic development of unserved areas in NCNG's franchised territory. Economic development will in turn provide a larger tax base, more employment opportunities, and a better quality of life.

11. All customers on NCNG's system stand to benefit from the expansion to be made possible by the expansion fund through system strengthening, improved load factor, increased throughput, and potential improvements in the economy in NCNG's franchised territory.

12 At the time of the filing of its Supplemental Request, NCNG had a total of $3,713,822 in final supplier refunds. NCNG has requested that supplier refunds of $3,713,822, plus applicable interest, be deposited into the expansion fund. In addition, NCNG has requested that an initial surcharge of five cents per dekatherm be approved for all customers except LOF.

13. G.S. 62-158(b) provides that funding for an expansion fund may include refunds to a local distribution company such as NCNG from the company's suppliers of natural gas and transportation services.

14. G.S. 62-136(c) provides,

> If any refund is made to a distributing company operating as a public utility in North Carolina of charges paid to the company from which the distributing company obtains the energy, service or commodity distributed, the Commission may, in cases where the charges have been included in rates paid by the customers of the distributing company, require said distributing company to distribute said refunds plus interest among the distributing company's customers in a manner prescribed by the Commission.

The Commission has ordered natural gas public utilities to return such supplier refunds to the utilities' customers. The Commission would have ordered NCNG to return the $3,713,822 at issue herein to its customers but for the provisions of G.S. 62-158.

15. The supplier refunds of $3,713,822, plus interest, held by NCNG are authorized sources of funding under G.S. 62-158, are just and reasonable sources of initial funding for the expansion fund, and should be transferred to the fund.

16. The Cities are customers on NCNG's system and, as such, are the only municipal gas distribution systems in the State that are customers of a natural gas public utility. Each City maintains its own natural gas distribution system and provides service to areas not served by NCNG. The Cities' municipal gas distribution systems have been profitable, enabling them both to expand their gas facilities and to use earnings from their gas businesses for non-gas related projects as well as for disbursements to the general funds of the Cities. The Cities have benefitted from the higher load factor on NCNG's system resulting from the expansion of NCNG's system over the years and will benefit from continued expansion of that system to serve customers in previously unserved areas.

17. The PWC is a customer of NCNG. PWC provides electric service to the public in and around Fayetteville. PWC's facilities include electric generation facilities fueled by natural gas. PWC also provides water and sewer utility services to the public. PWC's electric operations have been profitable, enabling it to fund improvements to its water and sewer systems, to give at least 5% of annual gross revenues to Fayetteville for its operating budget, and to transfer additional millions of dollars to Fayetteville for undesignated projects such as parks. PWC's electric rates are lower than CP&L and REA rates in the area. PWC reduced its electric rates last year, in part because of the low cost of natural gas.

18. In the preamble to the legislation enacting G.S. 62-158, the General Assembly found that the expansion of natural gas service benefits all customers in all customer classes of a local distribution company so that all customers should pay a fair and reasonably proportionate share of the cost of expanding natural gas service.

19. The inclusion of the Cities' and PWC's proportionate shares of supplier refunds in the expansion fund for NCNG will not unduly burden the Cities or PWC and is just and reasonable.

20. G.S. 62-48(b) provides for supplier refunds to be used for the Commission's legal counsel appearing before federal courts and agencies and related travel expenses of the Commission staff and the Public Staff. The statute also provides for the Commission to establish procedures for the natural gas public utilities to set aside reasonable amounts of supplier refunds for these purposes.

21. Appropriate procedures for reasonable amounts of supplier refunds to be set aside for purposes of G.S. 62-48 is a generic matter affecting all natural gas public utilities, not just NCNG. The Commission will issue a separate order establishing such procedures.

22. The Commission will defer ruling on the project proposal in the Sub 307 docket pending the expiration of time for taking appeal or the resolution of any appeal that may be taken in the Sub 306 docket. Since the request for a surcharge is dependent upon the net present value analysis of the proposed project, the Commission will not approve any surcharge at this time. The Commission regards the present Order as a final Order in the Sub 306 docket establishing an expansion fund for NCNG and approving initial funding.

23. NCNG shall give appropriate notice of the establishment of an expansion fund and approval of initial funding by bill insert.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence for these findings of fact is contained in NCNG's Petition, the Commission's files and records, and the testimony of NCNG witness Wells. These findings are essentially informational and uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

On September 17, 1992, CUCA filed a Motion to Dismiss NCNG's Petitions in these dockets on the grounds that G.S. 62-158 is unconstitutional under various provisions of the State and Federal Constitutions. For the most part, the briefs of parties and <u>amicus curiae</u> address the substantive merits of CUCA's constitutional arguments, but the Commission concludes that it has no authority to rule on these issues.

The Utilities Commission is an administrative agency of the General Assembly created for the principal purpose of carrying out the administration and enforcement of the Public Utilities Act. G.S. 62-23. As an administrative agency, the Commission has no authority except that specifically granted to it by the General Assembly. <u>State ex rel. Utilities Commission</u> v. <u>Southern Bell,</u> 307 N.C. 541, 545, 299 S.E. 2d 763 (1983). While the General Assembly has given the Commission substantial regulatory authority over public utilities, the General Assembly has not delegated authority to the Commission to determine the constitutionality of the General Assembly's own enactments. In the absence of the grant of such authority, the Commission is without power to hear and decide CUCA's constitutional challenge to G.S. 62-158.

The North Carolina courts have, in at least three cases, held that a North Carolina administrative agency does not have the authority to hear constitutional challenges to statutes. These cases are Insurance Company v. Gold, 254 N.C. 168, 118 S.E. 2d 792 (1961); In re Appeals of Timber Companies, 98 N.C. App. 412, 391 S.E. 2d 503 (1990); and Johnston v. Gaston County, 71 N.C. App. 707, 323 S.E. 2d 381 (1984), disc. rev. denied, 313 N.C. 508, 329 S.E. 2d 392 (1985). Although none of these cases involved the Utilities Commission, the Commission concludes that the reasoning applies to this Commission.

It is true that the Commission is given authority to act in a judicial capacity as provided in G.S. 62-60. This statute provides in part as follows:

> For the purpose of conducting hearings, making decisions and issuing orders, and in formal investigations where a record is made of testimony under oath, the Commission shall be deemed to exercise functions judicial in nature and shall have all the powers and jurisdiction of a court of general jurisdiction as to all subjects over which the Commission has or may hereafter be given jurisdiction by law.

The judicial power granted by this statute its clearly limited to matters arising within the scope of the Commission's activities. The Commission's judicial authority is further limited by the North Carolina Constitution. Article IV, Section 3 allows the General Assembly to give administrative agencies such judicial powers "as may be reasonably necessary as an incident to the accomplishment of the purposes for which the agencies were created." It is not reasonably necessary as an incident to implementation of G.S. 62-158 that the Commission rule on the constitutional challenge. Rather, it is appropriate for the Commission to assume the validity of statutes it is charged with implementing until there is a judicial decision to the contrary. 1 Am Jur 2nd, Administrative Law Section 185. Our decision herein is consistent with those of other utilities commissions collected at PUR Digest 3rd, Commissions Sections 29-30.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-11

The evidence for these findings of fact is found in the legislation enacting G.S. 62-158, and in the testimony of Company witness Wells, Public Staff witness Sessoms, CUCA witness Solomon, Federal Paper and Cape Industries witnesses Magnabosco and Lee, and Alcoa witness Stickney.

In order to establish an expansion fund for a natural gas public utility, the Commission must find that there are unserved areas within the company's franchised territory in which it would otherwise not be feasible for the company to construct natural gas facilities. G.S. 62-158(a). The Commission must also find that it is in the public interest to establish an expansion fund. Commission Rule R6-82(d); see also G.S. 62-2(9). The first two elements are not really in dispute.

In the rulemaking proceedings to implement G.S. 62-158, the Commission defined unserved areas in Rule R6-81(b)(5) as counties, cities or towns of which a high percentage is unserved. NCNG witness Wells testified that 14 of the 43 counties in NCNG's service territory have no natural gas service and that a number of counties are only partially served. Numerous persons involved in economic development and local government in eastern North Carolina testified concerning the unserved areas in NCNG's territory and the need for an expansion fund. Public Staff witness Sessoms testified that what constitutes an unserved area under G.S. 62-158 should be determined on a case-by-case basis but should include counties that are substantially unserved. It is clear from this evidence that there are unserved areas in NCNG's service territory.

NCNG witness Wells testified that the Company has conducted feasibility studies of the potential market demand for natural gas in unserved areas of its territory and determined that there are unserved areas that are not economically feasible to serve. CUCA witness Solomon read CUCA's response to an NCNG data request in which CUCA acknowledged that it does not deny that there are unserved areas in NCNG's territory into which expansion of natural gas facilities is economically infeasible. Witness Wells testified that NCNG, as a privately-owned small utility company, has limited capital resources to invest in expansion projects and that the Company has been carrying heavy construction budgets in recent years. The Company constructed over 100 miles of transmission pipeline from 1990 to 1992 to increase service in counties that previously had only limited natural gas service. Wells noted that even with substantial assistance from an expansion fund, the Company felt that only one project should be proposed at this time to keep NCNG and its customers from facing an undue burden. Expansion funds under G.S. 62-158 are not taxable under state law, and the IRS has determined in a letter ruling that such funds are also free of federal income taxes. NCNG would be unable to match this tax benefit through traditional financing methods. Recent changes in tax laws make customer contributions in aid of construction taxable. The Commission finds that there are unserved areas in NCNG's territory that are economically infeasible to serve by traditional financing methods.

The real issue in this docket is with the third requirement, that the Commission find establishment of the expansion fund to be in the public interest. As to this requirement, the Commission finds first and foremost that the General Assembly has largely made this policy decision already. G.S. 62-158 is the culmination of years of work through the General Assembly to expand natural gas service. Throughout this time, local industrial recruiters and government officials have argued the need for natural gas service in their areas in order to achieve economic development.

The General Assembly held several meetings in the late 1980s to explore the status of natural gas service in the State and the reason for unserved areas existing within the utilities' franchised territories. NCNG began investigating the feasibility of extending natural gas service to eight unserved counties in its territory sometime before 1988. NCNG developed a preliminary assessment of market potential and a possible pipeline route. NCNG then retained the consulting firm of Stone and Webster to continue the investigation. Stone and Webster studied 11 options for extending service in the area. It concluded that none of the options was economically feasible and that the projects could lead to large rate increases. The Stone and Webster study was presented to the Joint Legislative Utility Review Committee in the Fall of 1988.

The General Assembly enacted G.S. 62-36A in June 1989. This statute provides for the natural gas utilities to submit reports detailing their plans for providing natural gas service to areas of their territories in which such service is not available and for the Commission and the Public Staff to analyze and summarize these reports independently and provide their analyses to the Joint Legislative Utility Review Committee on a biennial basis. The utilities filed their first reports in January 1990. The Commission and the Public Staff submitted their analyses to the Committee in May 1990. NCNG's report, and the corresponding sections of the Commission's and the Public Staff's reports, focused on providing service to the unserved counties in NCNG's territory. The reports concluded that such service was not economically feasible by traditional funding methods.

The General Assembly began focusing on new financing methods to facilitate the extension of natural gas service, and G.S. 62-158 was enacted on July 8, 1991. The preamble to the legislation specifically states that the General Assembly finds it necessary and in the public interest to authorize special funding methods to facilitate the construction of natural gas facilities into and through unserved areas in the utilities' territories that would otherwise be infeasible. Further, the legislation adopted G.S. 62-2(9) which provides that it is the public policy of the State to facilitate the construction of natural gas facilities and the extension of natural gas service to promote the public welfare throughout the State and to authorize the creation of expansion funds to that end. Thus, it is clear to the Commission that the General Assembly has made the policy decision that it is necessary and in the public interest to authorize the special funding methods provided by G.S. 62-158 to facilitate the construction of facilities and the extension of natural gas service into unserved areas of the State where it would be economically infeasible to serve by traditional means in order to provide infrastructure to aid industrial recruitment and economic development. The Commission believes that the General Assembly intends for the Commission to exercise limited discretion as to whether a fund should be created for a particular natural gas utility.

Several parties addressed the issue of public interest in their testimony, and the Commission finds that this testimony bolsters the finding of public interest in this case.

NCNG witness Wells testified that the development of natural gas facilities in unserved areas of eastern North Carolina would help attract new industry to NCNG's territory. Wells noted that the economic development that would result from wider availability of natural gas would give the State a larger tax base, provide more employment opportunities and contribute to a better quality of life. He also noted that expansion of natural gas facilities would provide a more economical fuel to homes. Witness Wells' testimony concerning benefits to the public from expansion of natural gas to unserved areas of eastern North Carolina was affirmed by the 15 public witnesses who testified in this proceeding. These public witnesses have extensive experience in industrial recruitment, economic development and local government in eastern North Carolina. The public witnesses from Elizabeth City and Wayne, Duplin, Martin and Bertie Counties all testified to specific examples of their areas losing industrial prospects as a result of not having natural gas facilities in place. Bill Wall, with the Eastern North Carolina Chamber of Commerce representing 43 counties in eastern North Carolina, likewise told of lost industrial recruitment opportunities because of the lack of natural gas service. Several of the public witnesses testified that their towns or counties have infrastructure such as water, rail, roads, airports and access to state ports and have prime industrial sites and an adequate labor force, but lack natural gas to make economic development possible. Earl Stephenson from Northampton County testified that his county had recently obtained an industry which substantially increased the County's tax base and employment opportunities as a result of having natural gas in a portion of his county. John Howard testified that based on Wayne County's experience, 40% of industries considering Wayne County demanded natural gas. Witness Howard also testified concerning the loss of a large industry which would have used large volumes of natural gas but could not wait for the six months time it would take to bring natural gas to the site under consideration. The industry located outside NCNG's service territory. Howard testified that growth in Wayne County is in the area that is already served by natural gas.

CUCA witness Solomon and other witnesses testified that the establishment of an expansion fund for NCNG's system is not in the public interest and is not likely to lead to economic expansion even if gas facilities are built in unserved areas. CUCA presented a cross examination exhibit from the Department of Economic and Community Development to the effect that only between 22.8% and 35.3% of industrial prospects, depending on the category, make natural gas a mandatory requirement. Solomon acknowledged that many others would like to have the choice of gas.

NCNG witness Wells testified that customers on NCNG's system also can benefit directly from expansion projects under G.S. 62-158. Expansion projects such as the Wayne/Duplin Counties proposal enable NCNG to loop portions of its system to provide a more secure service to existing customers. Wells also testified that expansion projects would typically have high load factor industrial customers which would improve NCNG's annual load factor and result in spreading fixed costs over greater volumes.

The Commission agrees with various witnesses that natural gas is not the only requirement for economic growth in eastern North Carolina. However, the testimony cited above bolsters the finding that creation of an expansion fund for NCNG is in the public interest, including the interests of NCNG's system and customers. The Commission concludes that an expansion fund should be established.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-15

The evidence for these findings of fact is found in the testimony of Company witness Wells, Public Staff witness Hoard, and the witnesses for the Cities, CUCA, Alcoa, PWC, Federal Paper and Cape Industries.

Several intervenor witnesses testified that the supplier refunds represent overpayments and rightfully belong to NCNG's customers. NCNG witness Wells disagreed. Wells testified that NCNG customers were charged rates established by the Commission as just and reasonable and that G.S. 62-136(c) gives the Commission discretion as to the treatment of supplier refunds when NCNG receives them. There has never been a certainty that customers will receive at a later date a refund of amounts paid under rates determined by the Commission to be just and reasonable. At the time a customer uses gas, there is no assurance NCNG will receive a supplier refund for that period. Wells testified that when the Commission orders supplier refunds distributed to customers, the method typically used, placing a decrement in rates, does not match amounts paid by individual customers. Since customers come and go and since usage by customers can vary substantially with time, the amounts received through a decrement do not necessarily relate to what was paid. For instance, if a customer leaves the system it will get nothing while a new customer will receive a rate decrement. Wells also testified that if a customer is negotiating rates when the decrement to distribute refunds is in place, the refunds are meaningless as to that customer since the negotiated rate paid by the customer is tied to the alternative fuel price regardless of the reduction in the tariff rate because of the decrement.

The general rule in utility ratemaking is that after a utility's rates are lawfully set, the rates may not be cut (or a refund ordered) because an anticipated expense included in rates does not materialize. See, State ex rel. Utilities Commission v. Edminsten, 291 N.C. 451, 468-469, 232 S.E.2d 184 (1977). However, the law is different as to supplier refunds. G.S. 62-136(c) provides that the Commission may require a gas distribution company to return supplier refunds to its customers. The Commission has consistently exercised its authority under G.S. 62-136(c) to require that supplier refunds be returned to utility customers. The Commission would have done so as to the supplier refunds at issue here but for G.S. 62-158. In light of this new statute, the Commission concludes that the $3,713,822 in supplier refunds, plus interest, are reasonable sources of funding for the expansion fund and should be transferred to the fund.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF NOS. 16-19

The evidence for these findings is found in the testimony of Public Staff witnesses Hoard and Sessoms and the witnesses for the Cities and PWC.

The Cities witnesses O'Donnell, Whitley, Green, Batchelor, and Cox testified that the Cities should be exempt from funding the expansion fund because they own and operate their own natural gas distribution systems and they provide for the capital needs of those systems. They testified that denying them their share of the supplier refunds will have a negative impact on their ability to expand their municipal gas systems. The Cities do not oppose an expansion fund but are opposed to participating in funding it. The Cities request that if the Commission finds that Transco refunds must go toward expansion, they be allowed to set up their own expansion funds so that they can expand their own systems.

The Cities' witnesses acknowledged that a portion of their revenues are provided by customers outside city limits and that utility operations are profitable and make considerable cash contributions to the Cities' general funds. The Cities contend that the transfers from their gas utility systems to their respective general funds are analogous to a dividend paid by a corporation to a shareholder. Public Staff witness Sessoms disagreed with this analogy. Sessoms testified that the transfers are more like a return of capital or rebate.

The Cities' witnesses testified that supplier refunds are an integral source of funding for their gas system extension projects. The Cities apparently handle supplier refunds in different ways, however. Rocky Mount flows through all supplier refunds to its customers while other Cities hold the refunds for the purpose of stabilizing rates.

Public Staff witness Hoard noted that customers of the Cities are no different than customers in towns which are served directly by NCNG. Witness Hoard explained that the Cities' customers pay a retail rate which is comprised of the NCNG wholesale rate component covering NCNG's transmission, storage, and general plant costs, plus a city retail rate component that includes the distribution system costs of the city system. Hoard compared this situation to the customer served directly by NCNG which pays the same NCNG wholesale rate component, plus the retail component that covers NCNG's distribution system costs. Both sets of customers are presently required to pay rates high enough for NCNG to pursue the expansion of its transmission system through traditional capital financing means. Hoard testified that he did not see any basis for the customers of the Cities being treated differently than a customer situated in a municipality served directly by NCNG.

PWC witness Blanchard also objected to loss of the PWC's share of supplier refunds. Blanchard acknowledged that the PWC has transferred considerable sums to the City of Fayetteville over the last several years, that 50% of its customers live outside the city limits, and that PWC was able to lower its customers' electric rates last year due in part to the low cost of natural gas. Blanchard also testified that the PWC has increased its gas usage since NCNG's last rate case because the price of natural gas has been less than the PWC's alternate fuel and that the PWC's Board recently approved a project to improve the efficiency of its natural gas turbines. Blanchard testified that the PWC's rates are presently less than those charged by either CP&L or the REA electric cooperatives in the Fayetteville area.

Public Staff witness Hoard testified that the PWC situation is similar to that of CP&L. CP&L intervened in the Commission's rulemaking proceeding and asked to be exempted from contributing to expansion funds. CP&L was not granted an exemption, and Hoard argued that PWC should not be exempted either.

The Commission concludes that it is appropriate for all classes of customers to participate in the funding of the expansion fund. The Commission recognizes that the General Assembly intended that the expansion fund be funded from as broad a customer mix as possible. In the preamble to the legislation enacting G.S. 62-158, the General Assembly found that the expansion of natural gas service benefits all customers in all customer classes of a local distribution company so that all customers should pay a fair and reasonably proportionate share of the cost of expanding natural gas service. The Commission also recognizes that granting some customers exemptions will open the door to many other "special" circumstances. The Commission believes that the public interest is served best by requiring as broad as possible participation in the funding of the expansion fund.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

The evidence for these findings of fact is found in the testimony of Public Staff witness Hoard and in the orders and records of the Commission.

G.S. 62-48(b) authorizes use of supplier refunds to pay for the Commission's legal counsel appearing before federal courts and agencies and related travel expenses of the Commission staff and the Public Staff. For years, the Commission has retained legal counsel in Washington, D.C. to represent the Commission before the Federal Energy Regulatory Commission and federal courts. The Commission staff and the Public Staff incur travel expenses from time to time assisting Washington counsel. The Commission pays these expenses and periodically calls upon the natural gas utilities to reimburse the Commission proportionately out of their supplier refunds.

The Commission issued an Order on March 12, 1992, in Docket No. G-100, Sub 57, providing for each natural gas utility to hold final supplier refunds that it proposes for inclusion in an expansion fund in a separate bank account pending further order of the Commission. The Commission continued this procedure when it adopted rules to implement G.S. 62-158 on April 9, 1992. These orders did not address the use of supplier refunds for Washington counsel. Witness Hoard testified that NCNG currently maintains an account on a imprest fund basis which has a $7,775 balance, that the Company debits this account as it reimburses the Commission for Washington counsel, and that the Company then reimburses this account with a transfer of funds from its deferred gas cost account.

Witness Hoard recommended that approximately $12,000 of the supplier refunds at issue in this proceeding be set aside to increase the balance in the NCNG reserve account to $20,000 for Washington counsel. The Commission finds it unnecessary to do that since NCNG has received additional final supplier refunds, which are not at issue in this proceeding, which may be used for Washington counsel. However, witness Hoard's recommendation that the Company's accounting procedures be modified to ensure that Washington counsel is paid from supplier refunds is a good one. Since this matter affects all natural gas utilities, not just NCNG, the Commission will issue a separate generic order in the near future establishing appropriate procedures to coordinate the use of supplier refunds for Washington counsel pursuant to G.S. 62-48(b) with the use of supplier refunds for expansion funds under G.S. 62-158.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The original petition filed by NCNG on May 13, 1992, dealt with establishment of an expansion fund, approval of initial funding, and the Company's proposal for its first expansion project. Following a motion by the Public Staff, the Commission issued an Order on June 9, 1992, requiring that the Petition be divided into separate dockets. The two dockets were consolidated for purposes of a joint hearing, but the Commission ruled that for purposes of implementing G.S. 62-158, the issues of establishing an expansion fund and initial funding (the Sub 306 docket) should be separated from the request for approval of an expansion project (the Sub 307 docket).

The Commission regards the present Order as an final Order in the Sub 306 docket on establishment of an expansion fund and initial funding. CUCA has indicated that it intends to appeal the Commission's decision on establishment of a fund on grounds that G.S. 62-158 is unconstitutional. If such an appeal is taken and is ultimately successful, the Sub 307 docket will be rendered moot. Even if such an appeal is unsuccessful, any net present value determination that the Commission might decide now in connection with the project proposal in the Sub 307 docket will be outdated by the time the appeal is resolved. The Commission will therefore defer ruling on the Sub 307 docket pending expiration of the time for taking appeal. If no appeal is taken within the time allowed by G.S. 62-90, the Commission will proceed with the Sub 307 docket. If an appeal is taken, the Commission will of course be deprived of jurisdiction to proceed with the Sub 307 docket.

The request for a surcharge is dependent upon the net present value determination of the project proposal in the Sub 307 docket: the Public Staff argues that the supplier refunds are sufficient for this project without a surcharge. The Commission will therefore not approve any surcharge at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

Commission Rule R6-82(d) provides that the Commission shall require "appropriate notice of its decision" when an expansion fund is established. The Attorney General argues that the Commission should notify ratepayers by bill insert "that their supplier refunds have been diverted to the expansion gas fund consistent with North Carolina law." The Commission agrees. NCNG has given notice to its customers that $3,713,822 in supplier refunds are at stake in this proceeding, and the Commission finds it appropriate to notify customers that an expansion fund has been established for NCNG and that the supplier refunds have been transferred to it in order to carry out the intent of the General Assembly as expressed in G.S. 62-158.

IT IS, THEREFORE, ORDERED as follows:

1. That an expansion fund should be, and hereby is, created for NCNG in the Office of the State Treasurer for the purpose of constructing natural gas lines into unserved areas in NCNG's territory that are otherwise infeasible to serve in order to provide infrastructure to aid industrial recruitment and economic development;

2. That NCNG is hereby directed to transfer to the expansion fund the sum of $3,713,822 in supplier refunds held by it plus interest earned thereon pursuant to the provisions of the Commission's March 12, 1992 Order in Docket No. G-100, Sub 57; and

3. That NCNG shall notify its customers of the Commission's decision by sending a copy of the Notice attached hereto as Appendix A as a bill insert in its next billing cycle.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-21, SUB 306

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by North Carolina Natural Gas Corporation for the Establishment of an Expansion Fund and Approval of Initial Funding	PUBLIC NOTICE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission, upon petition of North Carolina Natural Gas Corporation (NCNG) and following a hearing at which several parties participated and presented testimony, entered an Order on February 8, 1993, establishing an expansion fund for NCNG and approving initial funding of the expansion fund in order to carry out the intent of the General Assembly as expressed in G.S. 62-158.

G.S. 62-158 was enacted by the General Assembly on July 8, 1991. The statute authorizes the Utilities Commission to "order a natural gas local distribution company to create a special natural gas expansion fund to be used by that company to construct natural gas facilities in areas within the company's franchised territory that otherwise would not be feasible for the company to construct." The statute goes on to provide that sources of funding for such an expansion fund may include "refunds to a local distribution company from the company's suppliers of natural gas and transportation services pursuant to refund orders or requirements of the Federal Energy Regulatory Commission."

NCNG advised the Commission that it is holding supplier refunds of $3,713,822, and NCNG petitioned to transfer these refunds to the expansion fund, once created. The Commission's Order approved this request and ordered NCNG to transfer $3,713,822, plus interest, to the expansion fund pursuant to G.S. 62-158.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

MOTOR TRUCKS - AUTHORITY GRANTED - COMMON CARRIER

DOCKET NO. T-3736, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of PTC of Mt. Airy, Inc., Post Office Box 1463, Mt. Airy, North Carolina 27030 - Application for Common Carrier Authority	)	FINAL ORDER OVERRULING EXCEPTIONS AND AFFIRMING RECOMMENDED ORDER

ORAL ARGUMENT HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, May 11, 1993, at 9:30 a.m.

BEFORE: Commissioner Robert O. Wells, Presiding, Chairman William W. Redman, Jr., and Commissioners Sarah Lindsay Tate, Julius A. Wright, Laurence A. Cobb, Charles H. Hughes, and Allyson K. Duncan

APPEARANCES:

For the Applicant:

David H. Permar, Hatch, Little & Bunn, Attorneys at Law, Post Office Box 527, Raleigh, North Carolina 27602
For: PTC of Mt. Airy, Inc.

For the Protestants:

Robert W. Kaylor, Bode, Call & Green, Attorneys at Law, Post Office Box 6338, Raleigh, North Carolina 27628
For: A. C. Widenhouse, Inc.; Puryear Transport, Inc.; Hilco Transport, Inc.; Southern Oil/Tidewater Fuels, Inc.; and Associated Petroleum Carriers, Inc.

BY THE COMMISSION: On April 6, 1993, Commission Hearing Examiner Barbara A. Sharpe entered a Recommended Order in this docket granting the application of PTC of Mt. Airy, Inc. (PTC), for a certificate of public convenience and necessity to transport Group 3, petroleum and petroleum products, liquid, in bulk in tank trucks; and Group 21, asphalt and asphalt products, including cutback and emulsions, in bulk in tank trucks; statewide.

On April 20, 1993, A. C. Widenhouse, Inc.; Puryear Transport, Inc.; Hilco Transport, Inc.; Southern Oil/Tidewater Fuels, Inc.; and Associated Petroleum Carriers, Inc. (Protestants), filed exceptions to the Recommended Order Granting Application.

By Order entered in this docket on April 21, 1993, the Commission scheduled an oral argument on exceptions for Tuesday, May 11, 1993, at 9:30 a.m.

The matter subsequently came on for oral argument on exceptions before the full Commission at the appointed time and place. Counsel for Protestants offered oral argument in support of the exceptions. Counsel for PTC offered oral argument in opposition to the exceptions and in support of the Recommended Order.

Based upon a careful consideration of the entire record in this proceeding, the Commission concludes that, with only one minor exception, all of the findings of fact, conclusions, and decretal paragraphs contained in the Recommended Order of April 6, 1993, are fully supported by the record; that the Recommended Order should be affirmed and adopted as the Final Order of the Commission; and that each of the exceptions filed by the Protestants should be overruled and denied. The Commission agrees with counsel for the Protestants that one of the conclusions on page 6 of the Recommended Order is incorrect since the record indicates that two shipper witnesses, not just one, are currently using the services of the Protestants. This change does not, however, cause the Commission to reach a decision different from that set forth in the Recommended Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the exceptions filed by Protestants with respect to the Recommended Order entered in this docket on April 6, 1993, be, and the same are hereby, denied.

2. That the Recommended Order entered in this docket by Hearing Examiner Barbara A. Sharpe on April 6, 1993, be, and the same is hereby, affirmed and adopted as the Final Order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of June 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. T-1039, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In The Matter Of NORTH CAROLINA INTRASTATE PETROLEUM RATE COMMITTEE OF THE NORTH CAROLINA TRUCKING ASSOCIATION, INC., Complainant v. WENDELL TRANSPORT CORPORATION, Respondent	)	ORDER ON COMPLAINT

HEARD: Tuesday, March 23, 1993, at 10:00 a.m., through Wednesday, March 24, 1993, in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

BEFORE: Commissioner Charles H. Hughes, Presiding; Commissioners Robert O. Wells and Allyson K. Duncan

APPEARANCES:

For North Carolina Intrastate Petroleum Rate Committee of the North Carolina Trucking Association, Inc.:

Ralph McDonald and Cathleen M. Plaut, Bailey & Dixon, Attorneys at Law, Post Office Box 1351, Raleigh, North C'rolina 27602-1351

For Wendell Transport Corporation:

Clarence M. Kirk and Donna S. Stroud, Kirk, Gay, Kirk, Gwynn and Howell, Attorneys at Law, Post Office Box 729, Wendell, North Carolina 27597

For the Using and Consuming Public:

Robert B. Cauthen, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

Appearing Pro Se:

Danny P. Evans, 907 Olde Manor Lane, Garner, North Carolina 27529

BY THE COMMISSION: On April 16, 1992, Complainant North Carolina Intrastate Petroleum Rate Committee of the North Carolina Trucking Association, Inc. (PRC) filed a Complaint alleging that Respondent Wendell Transport Corporation's (Wendell) discounted rates in Item 9005 of Wendell Transport Corporation NCUC

Tariff No. 17A (Tariff No. 17A), applying on petroleum and petroleum products in bulk in tank trucks, are noncompensatory, unjust, unreasonable, discriminatory, provide for unreasonable preferences and advantages, and constitute an unfair and destructive competitive practice in violation of G.S. 62-259 and G.S. 62-140. On April 21, 1992, the Commission issued its Order Serving Complaint, and on June 9, 1992, Wendell filed its Answer to the Complaint. On June 29, 1992, the Commission issued its Order Scheduling Hearing on Wednesday, August 12, 1992.

On July 28, 1992, Wendell filed its Motion for Postponement of the August 12, 1992, hearing. On August 4, 1992, the Commission issued its Order Continuing Hearing to a Date to be Announced. On August 7, 1992, the Commission issued its Order Scheduling Hearing on September 24, 1992. On September 16, 1992, the Commission issued its Order Allowing Discovery and Canceling Hearing.

On September 9, 1991, Danny P. Evans filed a Petition to Intervene in this docket. PRC filed a Response to Evans' Petition to Intervene on September 16, 1992. On September 21, 1992, Danny P. Evans filed a Motion to Make the Public Staff a Party to this Proceeding, and an Amendment and Correction to the Petition to Intervene and Answer to Response to Petition to Intervene. On September 23, 1992, the Public staff filed Comments on Evans' Motion.

On September 25, 1992, Marathon Oil Company filed its Petition for Intervention and Motion for Protective Order. On September 28, 1992, PRC filed its response to Marathon Oil Company's Petition for Intervention and Motion for Protective Order. On October 15, 1992, the Commission, by consent of PRC, Wendell, and Marathon Oil Company, issued a Consent Order Allowing Marathon Oil Company's Petition for Intervention and Motion for Protective Order.

On October 8, 1992, the Commission issued its Order Affirming Discovery Order and Denying Motion to Set Aside, in which it scheduled a hearing on the Complaint for December 15, 1992. On November 25, 1992, in its Order Fixing Time to File Responses and Continuing Hearing, the Commission continued the hearing to a date to be announced.

On November 19, 1992, the Commission issued its Order Allowing Intervention in which it allowed Danny P. Evans' Petition to Intervene and denied Evans' Motion to Make the Public Staff a Party in this proceeding. On February 1, 1993, the Commission entered its Order Granting Protective Order and Scheduling Hearing on March 23, 1993.

Throughout the course of this proceeding, the Commission issued numerous orders regarding discovery. Specifically, in its September 16, 1992, Order Allowing Discovery and Canceling Hearing, the Commission allowed PRC's Motion to Compel Discovery and denied Wendell's Motion for Protective Order; on October 8, 1992, the Commission entered its Order Affirming Discovery Order and Denying Motion to Set Aside, in which it reaffirmed its September 16, 1992, Order Allowing Discovery; on February 1, 1993, the Commission entered its Order Granting Motion for Protective Order in which it allowed PRC's Motion for Protective Order; on March 8, 1993, the Commission issued its Order Granting Motion for Protective Order in which it allowed PRC's Motion for Protective Order; at the hearing on March 23, 1993, the Commission allowed PRC's Motion to Quash and allowed, in part, PRC's Motion to Strike.

The public hearing was held as scheduled beginning on March 23, 1993. PRC presented the testimony and exhibits of David Fesperman, consultant in the field of transportation marketing, costing and pricing analysis, and Barbara J. Duke, traffic manager of Eagle Transport Corporation.

Wendell presented the testimony and exhibits of Waylon Lynch, Executive Vice President of Wendell Transport Corporation, Jon Stansbury with Marathon Oil Company, and Dr. J. Carl Poindexter, Jr., Associate Professor of Economics and Business at North Carolina State University.

Danny P. Evans testified on his own behalf.

Based on the pleadings, the testimony and exhibits, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PRC is an association of motor common carriers of petroleum and petroleum products that participate in North Carolina Trucking Association, Inc., Agent, Petroleum Tariff No. 5-Y. Most of the petroleum carriers in North Carolina participate in Tariff No. 5-Y.

2. Wendell is a motor common carrier of petroleum and petroleum products operating under Certificate No. C-140. Wendell does not participate in Tariff No. 5-Y.

3. On January 15, 1992, in NCUC Docket No. T-1039, Sub 18, Wendell filed an application for authority to publish Tariff No. 17A in order to effect a five percent (5%) rate increase.

4. On February 14, 1992, the Commission issued its Recommended Order Approving Tariff Filing and its Order Adopting Recommended Order, allowing Tariff No. 17A to become effective February 15, 1992.

5. The application for authority to publish Tariff No. 17A gave no notice that Items 9000, 9005, and 9010 of Tariff No. 17A provide for a 23% discounted rate if a customer tenders a minimum of $832,000.00 in annual revenue.

6. On April 16, 1992, PRC filed a Complaint alleging that the discount rate provisions in Items 9000, 9005, and 9010 were unjust, unreasonable, discriminatory, provide for unreasonable preferences and advantages and constitute an unfair and destructive competitive practice.

7. In its justification data submitted in Docket No. T-1039, Sub 18, Wendell supplied a "giving effect" income statement for January 1991 through June 1991. The 23% discount established in Item 9010 of Tariff No. 17A was not considered in the "giving effect" income statement.

8. A recalculation of the "giving effect" income statement, which takes into account the discounted rates in Item 9010, shows an operating ratio that exceeds 100%.

9. In preparing justification data and testimony in this proceeding, Wendell did not use the uniform cost allocation method or any other cost allocation method previously approved by this Commission.

10. The uniform cost allocation method is appropriate to determine whether a rate is just and reasonable. Using the uniform cost allocation method, the operating ratio derived from Wendell's actual experience under Item 9010 from April 1992 through September 1992 is 100.93.

11. The discounted rates in Item 9010 of Tariff No. 17A are not compensatory.

12. At least one carrier lost business as a result of the discounted rates in Item 9010.

13. Wendell's other ratepayers are subsidizing the Item 9010 traffic.

14. The noncompensatory rates in Item 9010 are unjust, unreasonable, discriminatory, provide for unreasonable preferences and advantages, and constitute an unfair and destructive competitive practice in violation of G.S. 62-259 and G.S. 62-140.

15. The discounted rate provision in Item 9010 of Tariff No. 17A is not just and reasonable, and should be canceled.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence for these findings of fact is contained in PRC's Complaint, the Commission's records, and the testimony of PRC witness Fesperman. These findings are generally informational and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-6

The evidence for these findings of fact is found in the Commission's records, the testimony of PRC witnesses Fesperman and Duke, and the testimony of Wendell witnesses Lynch and Stansbery.

In its application for authority to publish Tariff No. 17A in Docket No. T-1039, Sub 18, no notice was given of the 23% discount in Item No. 9010. The transmittal letter for Tariff No. 17A referenced a "Rate Increase Application" and made no mention of the rate reductions in Item 9010. Waylon Lynch, Wendell's Executive Vice President, filed testimony in Docket No. T-1039, Sub 18, in which he stated only that Wendell was seeking permission to increase its rates by 5%. Mr. Lynch did not submit any testimony concerning the Item 9010 rate reductions.

Wendell did not comply with the Commission's Rules or its own internal tariff rules when it filed Tariff No. 17A in Docket No. T-1039, Sub 18. NCUC Rule R4-4 provides in part:

> (a) Written notice, in triplicate, containing a brief explanation of the character of any reason for any intended changes in tariff schedules shall be filed with the Commission not later than the date said schedule is filed.

* * * * *

(b) All tariffs, supplements and revised pages shall indicate changes from preceding issues by a printer's tear drop symbol or (R) to denote reductions. . .. The proper symbol must be shown directly in connection with each change.

Wendell's own Explanation of Abbreviations and Reference Marks in its Tariff No. 17A states that the symbol (R) denotes a reduction. Wendell did not use any symbol in Tariff No. 17A to denote any rate reductions, and its tariff filing did not comply with NCUC Rule R4-4.

Neither the February 3, 1992, Commission Conference Agenda nor the Order of Investigation and Notice of Hearing in Docket No. T-1039, Sub 18 provided any notice of the rate reductions in item 9010 of Tariff No. 17A. PRC initiated this proceeding after one of its members found out about the 23% discount provision in Item 9010.

PRC witness Fesperman compared Wendell's Tariff No. 17A to the North Carolina Trucking Association, Inc., Agent, Petroleum Tariff No. 5-Y (Tariff 5-Y). He testified that the "call and demand" scale of rates in the two tariffs were identical. "Call and demand" rates apply to the occasional or small shipper who requests the carrier's services. The "key-stop" provisions in the two tariffs are also identical. "Key-stop" provisions are volume discounts of 15% available to certain shippers who meet specific criteria set out in the tariff. The crucial distinction between the two tariffs is that Item 9010 of Tariff No. 17A provides for a 23% discounted rate if a customer tenders a minimum of $832,000.00 in annual revenue. In addition, the only difference between Wendell's "key-stop" provisions and the discounted rate provision in Item 9010 is the $832,000.00 revenue figure. Wendell can provide the same service to any shipper under its "key-stop" provisions that it can provide to a shipper under Item 9010. The only shipper taking advantage of the discounted rates in Item 9010 of Tariff 17A is Marathon Oil Company (Marathon).

Tariff No. 17A is silent concerning any rights or remedies Wendell might have for recovery of undercharges if Marathon traffic fails to generate $832,000.00 in annual revenue. Wendell's witness Stansbery testified that he had been told that if Marathon's annual revenue was less than $832,000.00, Marathon "might be asked to pay the difference," but he could not say whether that statement was true or not.

The Commission is unpersuaded that the service provided by Wendell under Item 9010 is any different from the service provided under Wendell's "key-stop" provisions. There is no requirement for dedication of equipment under Item 9010, and the only distinction between Item 9010 and the "key-stop" provisions is the $832,000.00 revenue requirement. The fact that Wendell may have increased its equipment utilization by assigning two of its units to handle the Marathon traffic on a 24-hour basis does not justify rates that do not cover costs.

Wendell's initial bid to Marathon for the issue traffic was a 15% discount off of its "call and demand" rates. In response to Wendell's bid, Marathon indicated that it was considering putting its own equipment in North Carolina. Wendell then went back to Marathon and asked what it would take for Marathon not to put their company equipment in North Carolina. Marathon informed Wendell that it would take a 19% discount, and Wendell assented. When a subsequent 5% increase went into effect, Marathon would not allow Wendell to apply the increase to the Marathon traffic.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-10

The evidence for these findings of fact is found in the testimony and exhibits of PRC witness Fesperman and Wendell witness Lynch.

G.S. 62-146(g) provides in part:

> In any proceeding to determine the justness or reasonableness of any rate of any common carrier of property by motor vehicle, there shall not be taken into consideration or allowed as evidence any elements of value of the property of such carrier, good will, earning power, or the certificate under which such carrier is operating, and such rates shall be fixed and approved, subject to the provisions of subsection (h) hereof, on the basis of the operating ratios of such carriers, being the ratio of their operating expenses to their operating revenues, at a ratio to be determined by the Commission....

(Emphasis added). "Just and reasonable rates for intrastate common carriers are to be determined by the Commission on the basis of the ratios of the carriers' operating expenses to their operating revenues." State ex rel. Utilities Commission v. Motor Carriers' Traffic Association, Inc., 16 N.C. App. 515, 517 (1972).

> An operating ratio of one hundred percent means that for every dollar of freight revenue received, the carrier spends a dollar in operating expenses. When the operating ratio exceeds one hundred percent, it means that the expenses exceed the revenues. The lower the operating ratio, the more profitable the operation is to the carrier.

State ex rel. Utilities Commission v. Attorney General of North Carolina, 2 N.C. App. 657, 660 (1968).

On July 30, 1980, this Commission entered its Order Approving Rate Increase in In the Matter of Motor Common Carriers- Proposed Increase in Rates and Charges Applicable on Shipments of Asphalt, in Bulk, in Tank Trucks, Docket No. T-825, Sub 257. In its Order, the Commission directed:

> That representatives of the Public Staff and the Respondents shall have a conference within three months of entry of this Order to discuss a uniform methodology for compiling financial data to be used in proceedings involving future tariff filings supplanting or supplementing the involved tariff.

On October 3, 1980, the Public Staff filed a report with the Commission in Docket No. T-825, Sub 257, in which it submitted the uniform cost allocation method and recommended that the method be adopted by the Commission for use in compiling financial data in future tariff filings involving the transportation of asphalt in intrastate commerce.

The uniform cost allocation method is a matrix that allocates costs on the basis of revenue, miles, and shipments. The Commission has consistently applied the uniform cost allocation method to the transportation of asphalt and petroleum and petroleum products. See e.g., Order Granting Exceptions and Denying Proposed Rate Adjustments, In the Matter of Infinger Transportation Co., Docket No. T-825, Sub 276 (October 27, 1983); Order Vacating Suspension and Allowing Rate Increase, In the Matter of motor Common Carriers - Suspension and Investigation of Proposed 5% Increase in Rates and Charges Applying on Tariff NCTA No. 5-V, Item 4 Petroleum and Petroleum Products, in Bulk, in Tank Trucks, Scheduled to Become Effective on July 9, 1989, Docket No. T-825, Sub 310 (August 7, 1989). In In the Matter of Infinger Transportation Co., Infinger did not use the uniform cost allocation method in preparing justification data and testimony in support of its tariff filing. The Commission held that the alternative cost allocation method proposed by Infinger was not appropriate for determining fair and reasonable rates, and that Infinger was required to use the uniform cost allocation method to show that its rates were just and reasonable.

In the present docket, Wendell never presented an operating ratio based on North Carolina intrastate revenue or expenses for any period of time under Item 9010 using the uniform cost allocation method. Wendell improperly allocated costs on a per mile basis in calculating its operating ratios. Mileage alone is not a sufficient basis for rates. State ex rel. Utilities Commission v. North Carolina Motor Carriers Assn', 253 N.C. 432 (1960). Mr. Fesperman testified that allocating costs on a per mile basis was inappropriate because all costs do not accrue on a per mile basis. Costs allocated solely on a per mile basis understate costs for short hauls, and overstate costs for long hauls. Indeed, Mr. Lynch testified that Wendell would not haul a load of petroleum over a short distance based on per mile costs because actual costs would be greater. Accordingly, the operating ratios derived through Wendell's cost allocation method cannot be used to justify the discounted rate provision in Item 9010.

Wendell did not take into account the discount in Item 9010 when it submitted its giving effect income statement for the first six months of 1991 in Docket No. T-1039, Sub 18. When Mr. Fesperman initially recalculated Wendell's giving effect income statement, he assumed that $832,000.00 in annual revenue would have been subject to the Item 9010 discounts. In his original calculation taking the Item 9010 discounts into effect, the operating ratio was 104.45. At his March 3, 1993, deposition, Mr. Lynch testified that Wendell had only $600,000.00 in traffic subject to the Item 9010 discounts. Based on Mr. Lynch's deposition testimony, Mr. Fesperman determined that Wendell's operating ratio was 101.16. At the hearing in this docket, Wendell's witness Lynch testified that his deposition testimony was incorrect, and that Wendell actually had $765,594.00 in 1991 revenue that would have been subject to the Item 9010 discount. No recalculation of Wendell's 1991 giving effect income statement was performed using the $765,594.00 figure; however, it is obvious that Wendell's operating ratio would have exceeded 101.16. In calculating Wendell's operating ratios, Mr. Fesperman used the uniform cost allocation method as required by this Commission.

Mr. Fesperman also submitted the following calculation of Wendell's operating ratios based on Wendell's actual revenue and expenses for the period April 1992 through September 1992:

	System	Tariff No. 17A	Item 9010
Revenue	$3,342,572	$1,111,549	$309,580
Expenses	$3,269,174	$1,092,450	$312,453
Operating Ratio	97.80	98.28	100.93

Based on the entire record in this proceeding, the Commission is unpersuaded that the cost allocation methodology incorporated by Wendell is appropriate for determining fair and reasonable rates. The Commission believes that the uniform cost allocation method is appropriate and should be the basis for determining whether Wendell's rates are fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-15

The evidence for these findings of fact is found in the testimony and exhibits of PRC witnesses Fesperman and Duke, and Wendell witnesses Lynch and Poindexter.

All of the analyses performed using the uniform cost allocation method show an operating ratio over 100% for transportation performed under Item 9010. PRC witness Duke testified that Eagle Transport Corporation lost Marathon traffic in Charlotte because Wendell had offered the 23% discount off of its "call and demand" rate level. Ms. Duke further testified that Eagle Transport Corporation would not be able to cover the costs of that traffic if it gave Marathon the discount offered by Wendell.

> Generally speaking, the present regulatory system is designed to insure that common carriers are available to ship goods for whomever calls upon their services. It is fundamental that all who ship goods with common carriers are required to be treated equally with respect to the same category of service.

State ex. rel. Utilities Commission v. Bird Oil Co., 47 N.C. App. 1, rev'd on other grounds, 302 N.C. 14 (1980). The purpose of regulating transportation is to enable all shippers, regardless of market power, to get their goods to market on equal footing. Transportation rate levels must be nondiscriminatory in order to preserve equal access to the market.

Wendell's rates under Item 9010 do not cover its costs. These noncompensatory rates provide Marathon with an unreasonable advantage or preference. Under the discounted rates in Item 9010, Marathon can get its goods to market at a rate level that is less than Wendell's costs. The rest of Wendell's ratepayers are, in effect, subsidizing Marathon. The following comparison of Wendell's revenue, expenses, and operating ratios from April through September 1992 for all traffic under Tariff No. 17A, traffic subject to the discount in Item 9010, and traffic not benefiting from the Item 9010 discounts demonstrates that Wendell's other ratepayers are paying for the benefit Marathon enjoys:

	Tariff No. 17A	Item 9010	All Others
Revenue	$1,111,549	$309,580	$801,969
Expenses	$1,092,450	$312,453	$779,997
Operating Ratio	98.28	100.93	97.26

In support of his position that the discount provisions in Item 9010 are compensatory, Wendell witness Lynch referred to Wendell's 1991 and 1992 financial statements. In 1991, Wendell suffered a $46,833.36 loss, while in 1992, Wendell had a profit of $262,124.54. Mr. Lynch testified that, "We have not made any other significant changes in our business operations that would account for such a dramatic change." Mr. Lynch further testified that the increased business under the discounted rates, and the increased efficiencies and utilization of equipment, helped Wendell become more profitable.

Wendell's own exhibits and the testimony of PRC witness Fesperman indicate that Wendell's 1992 profit was not the result of the discounted rates in Item 9010. Wendell's 1992 profit was due to the increase in profitable propane operations, the elimination of unprofitable flatbed operations, and a gain on sale of equipment. The Commission concludes that the discounted rates in Item 9010 do not cover Wendell's costs and are not justified.

G.S. 62-140(a) states in part:

> No public utility shall, as to rates or services, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage.

G.S. 62-259 provides that it is declared the policy of this State "to prevent discrimination, undue preferences or advantages, or unfair or destructive competitive practices between all carriers...."

The Commission concludes that Wendell's noncompensatory rates are unjust and unreasonable. Allowing Wendell to maintain rate levels below cost would have a detrimental effect on other carriers whose rates cover costs and upon the general public, particularly small shippers. The Commission further concludes that the discounts in Item 9010 of Wendell's Tariff No. 17A constitute an unfair and destructive competitive practice that is harmful to the petroleum trucking industry and to the general public.

OTHER CONCLUSIONS

The Commission wishes to address the practice of discovery in this proceeding. The complaint of PRC was filed in this docket on April 16, 1992, and the answer of the Respondent was filed on June 9, 1992. The case was originally scheduled for hearing on August 12, 1992, but was subsequently continued to September 24, 1992, then to December 15, 1992, and finally to March 23, 1993, on which date the complaint was finally heard. Much of the intervening delay between the filing of the answer and the hearing on March 23, 1993, was caused by the failure of the Respondent to comply in good faith in all instances with the Complainant's requests for discovery and production of documents and the

Commission's Orders compelling discovery and production of documents. For example, Complainant PRC served Wendell with written discovery on June 30, 1992. By Motion dated July 28, 1992, Respondent requested, and received, an extension of time of an additional 30 days from August 4, 1992, to respond to the Complainant's request for discovery. On August 31, 1992, Respondent filed its Motion for Protective Order asking the Commission to excuse it from responding to the majority of the Complainant's discovery requests on the grounds that compiling such a response would be oppressive and cause undue burden and expense. Thus, Respondent waited almost 60 days from service of the Complainant's discovery requests before objecting to the discovery on such fundamental grounds.

By Order of September 16, 1992, the Commission denied the Respondent's Motion for a Protective Order and required the Respondent by September 25, 1992, to deliver to Complainant's counsel complete answers to the Complainant's discovery requests and all documents described in the request for production of documents. The hearing scheduled for September 24, 1992, was canceled and subsequently rescheduled to December 15, 1992. A further Order, issued October 8, 1992, granted the Respondent an additional period of time, to and including November 10, 1992, to comply with the Commission's Discovery Order of September 16, 1992.

Notwithstanding that the Respondent thus gained more than four months in which to comply with the original discovery requests served on June 30, 1992, the Complainant was compelled to file a Motion for Show Cause and Imposition of Sanctions on November 18, 1992; in these Motions, the Complainant alleged that Wendell's responses to Complainant's discovery served on November 10, 1992, were "incomplete and nonresponsive" in a number of respects. Finally, on January 6, 1993, counsel for the Complainant informed the Commission that the Respondent's Supplemental Answers to its Discovery "addressed most of the deficiencies we pointed out in our Motions with the exception of providing an income statement by tariff for calendar year 1991." Complainant elected, "in the interest of economy and expediency," not to go forward on its Motions for Show Cause and Sanctions if the Respondent provided Complainant with the missing income statement by February 8, 1993. The Commission issued an Order holding the Complainant's Motions for Show Cause and Sanctions in abeyance until further response from the Complainant. By this time, of course, the hearing on December 15, 1992, had to be canceled.

In its Orders requiring compliance with the Complainant's discovery requests, the Commission stated: ". . . The information sought in Complainant's Interrogatories and Request for Production of Documents is the type of information which Respondent as a common carrier, regulated by this Commission, would keep and maintain in the ordinary course of conducting its business. The Commission is satisfied that the Complainant has sufficiently shown a need for this information in its preparation for hearing on its complaint. This information is within the scope of discovery. . . "

The Commission wishes to express in the strongest terms its disapproval of the manner in which Wendell responded to the Complainant's discovery requests and the Commission's discovery orders in this docket. Wendell's failure to respond to discovery requests completely or in a timely manner inexcusably lengthened this proceeding, causing unwarranted additional expenses to the Complainant and delaying the Commission's consideration.

IT IS, THEREFORE, ORDERED as follows:

1. That Items 9000, 9005, and 901D of Wendell Transport Corporation NCUC Tariff No. 17A, be, and hereby are, canceled.

2. That Wendell Transport Corporation be, and hereby is, ordered to file appropriate supplements to Tariff No. 17A, canceling Items 9000, 9005, and 9010.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of July 1993.

North Carolina Utilities Commission
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. P-7, SUB 781

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Carolina Telephone and Telegraph Company - Lillington, Fayetteville, and Olivia Extended Area Service	)))	ORDER DENYING MOTION FOR RECONSIDERATION

BY THE COMMISSION: On December 14, 1992, the Commission issued an Order Authorizing Polling in Part. This docket concerned an extended area service (EAS) proposal involving four routes: Olivia to Lillington, Lillington to Olivia, Lillington to Fayetteville, and Olivia to Fayetteville. The Commission authorized polling for the first three routes but denied polling for the fourth, Olivia to Fayetteville.

In turning down the Olivia to Fayetteville route, the Commission noted that the percentage making calls (PMC) was 39.8%, well below the 45% PMC standard for intercounty EAS proposals between exchanges with common boundaries, even though the 4.77 community of interest factor (CIF) exceeds the 2.5 CIF standard for such proposals. The Commission also stated that the existence of a lower PMC with a higher CIF did not constitute a special circumstance under Rule R9-7(d)(3) such that the rule should be waived and polling authorized.

On February 11, 1993, Heins Telephone Company (Heins) filed a Motion for Reconsideration as to polling between Olivia and Fayetteville. Heins stated the following reasons:

1. The CIF factor and PMC factor have increased. Heins stated it had conducted a new toll calling study showing a combined CIF of 5.23 and a PMC of 42%. Heins noted that these were substantial increases, and even though the 42% PMC is still slightly shy of the standard, it will be only a short time before the PMC meets the criteria.

2. Residential growth in Olivia exchange. Heins stated that two new residential subdivisions, comprising a total of 515 lots, are being developed in the Olivia exchange within eight miles of the Fayetteville exchange. Of 30 lots sold in one of the subdivisions, 29 of the purchasers are employed by the military in Fayetteville.

3. Cost of polling. Heins stated it would be more cost effective to poll Olivia concerning the Fayetteville route at the same time it polls Olivia for the Lillington route.

On February 24, 1993, the Public Staff joined in Heins' motion for reconsideration. After restating some of Heins' arguments, the Public Staff stated that Heins had informed the Public Staff that the cost of polling is estimated to be $2,800 to $2,900, not including the cost of giving notice if EAS is approved.

On March 9, 1993, Carolina Telephone and Telegraph Company (Carolina) filed a Response to Motion for Reconsideration. While Carolina was not opposed to polling Olivia subscribers if special circumstances were found to warrant it, Carolina argued that it was inappropriate to authorize polling based on trends and expectations. In the instant case, the PMC standard is not met, and the Commission's standards for polling should not be compromised.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration of the filings in this docket, the Commission is of the opinion that Heins' motion for reconsideration as to polling should be denied.

The December 14, 1992, Order in this docket addressed the Olivia-to-Fayetteville route specifically as to the combination of a high CIF and a lower PMC. The Commission said:

> The rule was written in a conjunctive form and the Commission is not persuaded that such a situation should be viewed as a special circumstance. (December 14, 1992, Order at p. 4).

Heins has produced an updated calling study which shows that the PMC is still less than the 45% standard. Accordingly, the Commission believes that, based on the reasoning in the December 14, 1992, Order, the motion for reconsideration should be denied. However, at such time as the route does reach the standard in the EAS rules, the Commission will be prepared to consider the EAS proposal under the EAS rules with respect to Olivia and Fayetteville at that time.

IT IS, THEREFORE, ORDERED that Heins' February 11, 1993, motion for reconsideration be denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Chairman William W. Redman, Jr., and Commissioners Julius A Wright and Robert O. Wells dissent. They would grant the motion for reconsideration.

DOCKET NO. P-329

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Cherry Communications, a Division of Cherry Payment Systems, Inc., for a Certificate of Public Convenience and Necessity to Provide Long Distance Telecommunication Services	ORDER DENYING REQUEST FOR CONFIDENTIAL TREATMENT OF FINANCIAL STATEMENTS AND DELAYING HEARING

BY THE CHAIRMAN: On January 14, 1993, the Public Staff filed a Response to Application and Request for Confidential Treatment of Financial Statements filed by Cherry Communications, a Division of Cherry Payment Systems, Inc. (Cherry). The Public Staff requested that the Commission (1) deny Cherry's request to keep its financial statements confidential and (2) delay setting the application for public hearing until the deficiencies which the Public Staff has identified have been corrected and until the Applicant has corrected a tariff problem regarding operator-assisted calls and the discount for persons with speech and/or hearing impairments. In support of its request, the Public Staff showed as follows:

1. Cherry filed an application for a certificate of public convenience and necessity on October 30, 1992. In its application, Cherry requested authority to operate as a reseller of interexchange telecommunications services and as a provider of alternate operator services. Cherry states that it is a switchless reseller of Sprint's interexchange telecommunications services.

2. In its application, Cherry asserts it has the financial resources to conduct its proposed business. However, the Applicant's financial statements which support this statement were submitted under seal and Cherry has requested that its financial statements be treated as confidential.

3. The Applicant has provided no basis for its request of confidentiality. Furthermore, financial disclosures are required of all applicants for the certification sought by Cherry. Thus, by granting the confidentiality request of Cherry, the Commission would be granting special treatment to Cherry's application. Indeed, all previous requests by long distance applicants to keep financial statements confidential have been denied by the Commission. In addition, the Public Staff cannot determine whether Cherry has the financial fitness to operate in North Carolina until it has had an opportunity to review the financial statements of the Applicant.

4. The Public Staff recognizes that the resell interexchange market is highly competitive. The Public Staff concludes from this fact that individual firms should not be granted special treatment as Cherry has requested. Cherry is under no compulsion to enter the market in North Carolina. If Cherry cannot or will not comply with the same standard of financial disclosure asked of all other applicants, the Public Staff believes that the public interest will be better served by Cherry's remaining out of the market.

5. The Public Staff has completed its initial review of the application and finds the following deficiencies:

a. The application does not include a plan detailing the proposed methodology Cherry will employ to determine the monthly quantity of intrastate (interLATA and intraLATA) access minutes on its system in North Carolina. Although Cherry states it is a switchless reseller, it has not requested a waiver of this requirement.

b. The application does not contain a plan detailing Cherry's proposed methodology for determining the unauthorized intraLATA conversation minutes occurring on its facilities each month. Nor does the application include a letter, or indicate a letter is forthcoming from its underlying carrier, Sprint, that all intraLATA calls completed over unauthorized facilities will be accounted for and compensation paid in reports it submits.

c. The application does not include a plan detailing the proposed accounting methodology and necessary allocation procedures required to provide to the Commission the North Carolina intrastate jurisdictional financial operating results.

6. The Public Staff has also completed its initial review of Cherry's proposed tariffs and have identified two major areas of concern. First, Cherry has proposed to charge for operator assisted calls made from private pay telephones at rates which differ from the rates it intends to charge for calls made from other locations. Thus, Cherry has proposed to charges rates for operator assisted calls which discriminate depending simply upon the location of the caller. Second, the discount for persons with speech and/or hearing impairments does not reflect the 50% discount offered by all other interexchange carriers.

7. In addition, the Public Staff's review of the proposed tariffs indicates other inconsistencies with the Commission's rules and regulations. However, these inconsistencies should not prevent the application from being set for public hearing.

Cherry has not responded to the Public Staff's response.

After careful consideration of the filings in this docket, the Commission is of the opinion that the Public Staff's requests in this docket should be granted.

IT IS, THEREFORE, ORDERED as follows:

1. That Cherry's request to keep its financial statements confidential be denied.

2. That a public hearing on Cherry's application be delayed until such time as the deficiencies identified by the Public Staff above have been corrected and until the Applicant has corrected the tariff problem regarding operator-assisted calls at a discount for persons with speech and/or hearing impairments.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of January 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

TELEPHONE - EXTENDED AREA SERVICE

DOCKET NO. P-19, SUB 253

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of GTE South - Liberty (Cherokee County) to Murphy and Suit Extended Area Service	))	ORDER AUTHORIZING POLLING IN LIBERTY AND SUIT

BY THE COMMISSION: In April 1991, the Public Staff received a letter from Mrs. Linda Payne submitting newspaper articles and a petition bearing approximately 850 signatures in support of two-way, non-optional extended area service (EAS) between the Liberty area in Cherokee County, North Carolina, served by South Central Bell out of the Chattanooga, Tennessee, LATA to the adjacent exchanges in North Carolina of Murphy (Cherokee County seat) and Suit served by GTE South (formerly Contel of North Carolina) out of the Asheville, North Carolina, LATA. Signatures on the petition represented subscribers in all three exchanges. Additional support for the proposal has been received State Senator Robert Carpenter and State Representative Marty Kimsey, the Cherokee County Board of Commissioners, the Sheriff of Cherokee County, Hiwassee Dam High School, Ranger Elementary School, and other individual letters.

The Liberty area, with approximately 675 subscribers, is located in the southwestern-most part of North Carolina adjacent to the states of both Tennessee and Georgia. The area is part of South Central Bell's Copper Basin, Tennessee, exchange which has extensive EAS to exchanges in Tennessee and Georgia but none in North Carolina. The Liberty subscribers pay rates set by the Tennessee Commission for South Central Bell. The Murphy exchange, with approximately 6,500 subscribers and 17 air-line miles from Liberty, and the Suit exchange, with approximately 1,200 subscribers and eight air-line miles from Liberty, have EAS to each other as well as to the Andrews and Haysville exchanges. The Liberty area is the only area in Cherokee County that does not have local calling to Murphy, the county seat.

This matter came before the Regular Commission Conference on December 7, 1992. The Public Staff stated that due to the complex circumstances of this request, much time has been required to investigate it. At this time, the Public Staff said the following has been established:

1. South Central Bell has agreed to include the Liberty area in this proposal without involving the total Copper Basin exchange. This can readily be done since the Liberty area is in the North Carolina 704 area code and has its own prefix, 494, separate from the other prefixes in the Copper Basin exchange.

2. The Tennessee Commission has declined to be involved in this proposal since it concerns areas in North Carolina.

3. South Central Bell has agreed for Southern Bell to poll the Liberty subscribers using local rate increases of $1.22 for residence service and $4.42 for business service, both determined using the mileage portion of Southern Bell's EAS matrix tariff and the rate groups for South Central Bell. The current rates for Liberty are $7.55 for residence service and $27.05 for business service.

4. During the course of the investigation, GTE South has completed an EAS cost study for its Murphy and Suit exchanges to call the Liberty area. Based on the study results, the Public Staff recommends local rate increases of $0.27 for residence service and $0.68 for business service at each exchange to cover the incremental equipment costs necessary to provide the EAS. The Public Staff stated that it considers these levels of increase to be de minimis. The current rates for both Murphy and Suit are $16.79 for residence service and $42.88 for business service.

The community of interest factors (CIFs) and percentage making calls (PMCs) relevant to this proposal are as follows:

	CIF			PMC		
Exchange	Res.	Bus.	Combined	Res.	Bus.	Combined
Murphy to Liberty	0.32	0.82	0.41	8.9	18.6	10.6
Suit to Liberty	2.17	2.64	2.22	33.7	27.6	33.1
Liberty to Murphy	4.66	--	4.94	--	--	46.5
Liberty to Suit	2.32	--	2.37	--	--	34.0

The Liberty to Murphy and Liberty to Suit CIFs and PMCs were not available on December 7, 1992. The CIFs and PMCs as stated above were submitted by Southern Bell on March 12, 1993.

The Public Staff recommended that the Commission authorize Southern Bell to poll the Liberty subscribers regarding their interest in EAS to Murphy and Suit and, if that vote is favorable, to authorize GTE South to send no-protest notices to its Murphy and Suit subscribers reflecting the de minimis local rate increases recommended by the Public Staff. Alternatively, based on the information available as of December 7, 1992, the Public Staff suggested that the Commission schedule a hearing in Cherokee County to consider the level of public support and whether to proceed with a poll.

Representatives from GTE South and AT&T addressed the Commission on this docket.

The GTE representative noted that the proposed $0.27 and $0.68 increases would cover only incremental equipment costs and do not include any recovery of access charges. A rate fully compensatory to recover lost access charges would be $0.73 for residential and $1.87 for business. GTE also predicted that other EAS proposals involving its exchanges may be before the Commission at a later date. GTE also pointed out that the then-available CIFs and PMCs did not meet the Rule R9-7(d)(2) standards. Lastly, GTE asked the Commission to allow its subscribers to vote on the plan rather than handling it through no-protest letters.

AT&T noted that the proposal involved an interLATA route and, therefore, a degree of lost revenue for AT&T.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration of the filings in this docket, the Commission finds good cause to authorize Southern Bell to poll the Liberty area subscribers regarding their interest in EAS to the Murphy and Suit exchanges and GTE South to poll its Suit subscribers regarding their interest in EAS to Liberty.

Rule R9-7(d)(2) sets out the CIF and PMC standards that a proposal should meet to justify moving to a polling stage. Intra-county, county-seat proposals must meet a CIF standard of 1.0 or greater in the residential category or a CIF of 2.0 or greater in the residential and business categories combined on at least a one-way basis. Other intra-county proposals must meet on a one-way basis a CIF standard of 2.0 or greater in the residential category or a CIF of 2.5 or greater in the residential and business categories combined and a PMC standard of 25% or greater.

The instant case involves a county-seat route and an "other intra-county" route. For the county-seat route (Liberty to Murphy), the CIFs are 4.66 and 4.94 for residential and combined, respectively. For the "other intra-county" route (Liberty to Suit), the CIFs are 2.32 and 2.37 for residential and combined, respectively, and a PMC of 34%. It is thus clear that this proposal meets the CIF and PMC standards set out under Rule R9-7(d)(2).

With respect to the argument by GTE South that access charges should be included in the rate additive calculation, the Commission notes that Rule R9-7(e) states that "only the incremental equipment costs necessary to provide the EAS" will be included. Only a demonstration of "serious financial distress" from failure to consider lost toll revenues will justify a deviation from the rule. GTE South has neither quantified nor demonstrated "serious financial distress" in this case. In any event, GTE South has not disputed the correctness of the Public Staff's statement of the appropriate rate additive based on incremental equipment costs. Accordingly, the Commission believes that the appropriate rate additives are as the Public Staff has identified them.

The last question is whether Murphy and Suit should receive no-protest notices instead of being polled, as recommended by the Public Staff. The Public Staff argued that the applicable $0.27 residential and $0.68 business rate additives were de minimis relative to the current $16.79 residential and $42.88 business rates in the exchanges. Rule R9-7(h)(1) provides as follows:

> When the Commission determines that the public interest and need for EAS involving two exchanges is dominant in one direction, which is generally the case when the EAS request involves a large exchange and a small exchange, the Commission will determine on a case-by-case basis whether to poll both exchanges.

The Commission notes that Liberty and Suit are of a similar size, Suit being somewhat larger. Murphy, by contrast, should in this context be considered the "large exchange." Therefore, the Commission believes it to be reasonable to authorize polling for Suit but reserve the no-protest notice procedure for Murphy.

IT IS, THEREFORE, ORDERED as follows:

1. That Southern Bell and GTE South be, and the same hereby are, authorized to conduct a poll of the subscribers in Liberty and Suit, respectively, to determine their interest in the proposed EAS, utilizing the notice attached hereto as Appendix A as an example for polling.

2. That Southern Bell and GTE South file the results of their respective EAS polls broken down by business and residential categories with the Commission and the Public Staff as soon as the results are known.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. P-19, SUB 253

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of GTE South - Liberty (Cherokee County) to Murphy and Suit Extended Area Service	)))	NOTICE TO SUBSCRIBERS REGARDING EAS TO THE MURPHY AND SUIT EXCHANGES

NOTICE IS HEREBY GIVEN that Southern Bell Telephone and Telegraph Company (Southern Bell) has been authorized by the North Carolina Utilities Commission to poll the telephone subscribers in the Liberty, North Carolina, portion (494) of South Central Bell Telephone Company's Copper Basin exchange regarding the establishment of two-way, non-optional extended area service (EAS) to GTE South's Murphy (837) and Suit (644) exchanges. The purpose of the poll is to determine how many Liberty subscribers are in favor of paying higher monthly flat rates in lieu of the toll charges for calling to Murphy and Suit. Your existing local calling area will not be affected by this proposal.

<u>BASIC MONTHLY RATE INCREASES</u>
<u>FOR EAS TO MURPHY AND SUIT</u>

<u>Residence</u>	<u>Business</u>
$ 1.22	$ 4.42

You are requested to consider the question, mark your preference on the enclosed postcard ballot (stamped and preaddressed), and mail the ballot at your earliest convenience. Ballots postmarked after midnight ____________________ 1993, will not be counted in the vote. In addition, the ballot must be signed by the customer and a telephone number must be provided in order for the ballot to be counted in the vote. IF YOU WISH TO HAVE A VOTE IN THIS DECISION, YOU MUST RETURN THE MARKED BALLOT. The Commission's decision on the EAS proposal will be announced after the poll has been completed.

If you need additional information about this matter, you may contact your local telephone office at ( ) or the Public Staff, Post Office Box 29520, Raleigh, North Carolina 27626-0520, (919-733-2810).

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. P-76, SUB 33

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Saluda Mountain Telephone Company for an Adjustment of Its Rates and Charges	)	ORDER GRANTING PARTIAL RATE INCREASE

HEARD IN: Saluda Elementary School Auditorium, Saluda, North Carolina, on Tuesday, June 29, 1993, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, July 13, 1993, at 9:30 a.m.

BEFORE: Commissioner Allyson K. Duncan, Presiding, and Chairman John E. Thomas and Commissioner William W. Redman, Jr.

APPEARANCES:

For Saluda Mountain Telephone Company:

F. Kent Burns and Daniel C. Higgins, Burns, Day & Presnell, P.A., Attorneys at Law, Post Office Box 10867, Raleigh, North Carolina 27605

For AT&T Communications of the Southern States, Inc.:

William A. Oavis, II, Tharrington, Smith & Hargrove, Attorneys at Law, 209 Fayetteville Street Mall, Raleigh, North Carolina 27601

For the Public Staff:

Vickie L. Moir, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

BY THE COMMISSION: On October 30, 1992, Saluda Mountain Telephone Company (Saluda, Saluda Mountain, the Company, or the Applicant) filed a notice of intent to file an application for a general rate increase. On October 30, 1992, the Company also filed its request for waiver or modification of certain rate case minimum filing requirements. The Commission issued an Order on November 25, 1992, granting Saluda's request to waive certain minimum filing requirements. The Company filed its application on February 16, 1993. On February 26, 1993, the Company made a supplemental filing of materials inadvertently omitted from the Form P-1 Minimum Filing Requirements and a motion for waiver of Form P-1 Minimum Filing Requirements Item Nos. 44-48. The Commission issued an Order on March 10, 1993, granting Saluda Mountain's motion to waive the filing of Item Nos. 44-48 of the Form P-1 Minimum Filing Requirements. The Company filed revisions to Item Nos. 11 and 12A of the Form P-1 Minimum Filing Requirements on April 15, 1993.

By Order issued March 17, 1993, the Commission set the application for investigation and hearing, suspended the proposed rates and required public notice.

AT&T Communications of the Southern States Inc. (AT&T), filed a petition to intervene on April 23, 1993. On April 27, 1993, the Commission issued an Order allowing the intervention of AT&T.

On June 21, 1993, AT&T filed a motion for an extension of time to file its testimony. On June 22, 1993, the Public Staff filed a motion for an extension of time to file its testimony. By Orders issued on June 23, 1993, AT&T and the Public Staff were granted such extensions of time.

On June 28, 1993, at the same time it prefiled its testimony, the Public Staff filed the Stipulation of the Company and the Public Staff dated December 15, 1992.

The matter came on for hearing at the times and places shown above.

The following public witnesses appeared and offered testimony at the hearing in Saluda: Ceri Dando, Scott Beal, Linda Marshall, Jerry Pace, William Russell, Gunner Taylor, and Marlon Halford.

The Company presented the testimony and exhibits of Gene Owens, Carolina District Manager, TDS Telecom - Southeast Region, and James C. Meade, Manager of State Regulatory Affairs, TDS Telecom - Southeast Region. Mr. Meade also presented rebuttal testimony and an exhibit. Saluda was acquired by Telephone and Data Systems, Inc. (TDS) on December 31, 1989. This acquisition was finalized on March 7, 1990.

AT&T offered the testimony of Wayne A. King, Manager in the Network Services Division of AT&T.

The Public Staff presented the testimony and exhibits of Robert A. Goetz, Leslie C. Sutton, William J. Willis, Jr., and John T. Garrison, Jr., Utilities Engineers, Public Staff Communications Division, and Bridget C. Szczech, Staff Accountant, Public Staff Accounting Division.

On September 2, 1993, the Commission entered an Order requesting Saluda Mountain and the Public Staff to file certain specified information. The Company and the Public Staff made their filings in response to that Order on September 8, 1993.

Based upon the foregoing, the evidence adduced at the hearings, the Stipulation entered into by the Company and the Public Staff, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. The Applicant, Saluda Mountain Telephone Company, is a public utility as defined by G.S. 62-3(23). Saluda Mountain is subject to the jurisdiction of and is properly before this Commission for a determination of the justness and reasonableness of its proposed rates and charges.

2. By its application, the Company seeks rates to produce additional gross annual revenues of $158,620.

3. The test period consisting of the 12 months ended September 30, 1992, is representative and appropriate for use in this proceeding.

4. The quality of service provided by Saluda Mountain is adequate.

5. The appropriate depreciation rates for Saluda Mountain are reflected in Appendix A, attached hereto.

6. It is appropriate to increase plant in service by $97,045 to reflect actual post-test year plant additions.

7. It is appropriate to increase plant in service by $1,255 to capitalize legal fees incurred during the test year to secure capital leases.

8. It is appropriate to remove $45,112 from plant in service related to excess line card investment.

9. The appropriate level of telephone plant in service is $2,273,748.

10. It is appropriate to decrease accumulated depreciation by $21,694 related to the actual post-test year plant additions.

11. It is appropriate to increase accumulated depreciation by $34 related to the capitalized legal fees.

12. It is appropriate to decrease accumulated depreciation by $2,440 related to the excess plant adjustment.

13. It is appropriate to increase accumulated depreciation by $3,986 to reflect the complete recovery of Customer Premises Wiring.

14. It is appropriate to decrease accumulated depreciation by $2,942 to reflect the adjustment made to end-of-period depreciation expense.

15. The reserve deficiencies for Central Office Equipment (COE) Step-by-Step and Aerial Wire are $60,070 and $46,652, respectively, and should be amortized over a 10-year period.

16. It is appropriate to increase accumulated depreciation by $38 to reflect amortization of the reserve deficiency in Other Work Equipment.

17. The appropriate level of accumulated depreciation is $189,040.

18. The appropriate level of working capital is $35,019 consisting of $24,947 of cash working capital and $14,842 of materials and supplies, reduced by $4,770 of average tax accruals.

19. The appropriate level of accumulated deferred income taxes is $16,179.

20. It is appropriate to reduce rate base by $2,880 to reflect unfunded postretirement benefits.

21. It is appropriate to reduce rate base by $10,225 to reflect the unamortized balance of the Customer Premises Equipment (CPE) gain.

22. It is appropriate to flow back the CPE gain to Saluda's ratepayers over a five-year period.

23. Saluda Mountain's reasonable original cost rate base used and useful in providing telephone service within the State of North Carolina is $2,090,443. The rate base consists of telephone plant in service of $2,273,748 and working capital of $35,019, reduced by accumulated depreciation of $189,040, deferred income taxes of $16,179, unfunded postretirement benefits of $2,880, and an unamortized CPE gain of $10,225.

24. It is appropriate to adjust end-of-period revenues by $3,358 to reflect the penetration level actually achieved by Saluda Mountain for touchtone calling as of July 1993.

25. It is appropriate to adjust end-of-period revenues by $2,541 to reflect the penetration level for custom calling features actually achieved by Saluda Mountain as of July 1993.

26. It is appropriate to decrease local service revenues by $841 to correct an overstatement of public telephone coin revenues.

27. The appropriate level of interLATA network access revenue is $64,974.

28. The appropriate level of Universal Service Fund (USF) revenues is $147,340.

29. The appropriate level of intraLATA long distance revenue to recognize in this proceeding is $116,316.

30. The appropriate level of interLATA billing and collection revenue to be included as part of miscellaneous revenues is $14,568.

31. It is appropriate to increase test year miscellaneous revenues by $5,564 to reflect the end-of-period level of directory revenues.

32. It is appropriate to increase test year miscellaneous revenues by $153 to reflect an adjustment to pole rental revenue.

33. It is appropriate to increase test year miscellaneous revenues by $2,100, to reflect one-year of the flowback of the CPE gain to the Company's ratepayers.

34. The appropriate level of uncollectibles is $2,969.

35. The Applicant's operating revenues, net of uncollectibles, for the test year, under present rates, after accounting, pro forma and end-of-period adjustments are $486,594.

36. It is appropriate to increase operating expenses by $1,200 to reflect actual salary levels as of July 1, 1993.

37. It is appropriate to increase operating expenses by $204 to reflect actual payroll taxes and benefits corresponding to actual salary levels as of July 1, 1993.

38. It is appropriate to remove $3,784 from plant specific operations expenses for the central office building rent expense that is not an ongoing expense. The Company was scheduled to cease operations in the building by May 1993.

39. It is appropriate to amortize over a five-year period the cost of $1,840 incurred by Saluda for the training of a Barnardsville Telephone Company (Barnardsville) employee to serve as an emergency backup maintenance person for the Company's newly installed digital switch.

40. It is appropriate to include in the cost of service the training costs in the amount of $1,697 incurred during the test year for Saluda employees.

41. It is appropriate to increase plant specific operations expense by $5,165 to reflect the adjustment to pole rental expense.

42. It is appropriate to amortize the amount of $8,745 for TDS excess affiliated charges over a five-year period and, thus, include $1,750 in the Company's cost of service as an operating expense.

43. It is appropriate to increase depreciation and amortization expense by $5,098 to reflect one year of depreciation on the actual post-test year plant additions.

44. It is appropriate to increase depreciation and amortization expense by $30 to reflect one year of amortization on the capitalized legal fees.

45. It is appropriate to decrease depreciation and amortization expense by $2,444 to reflect the removal of excess line card investment.

46. It is appropriate to decrease depreciation and amortization expense by $2,631 to reflect the end-of-period level of depreciation expense.

47. It is appropriate to increase depreciation and amortization expense by $735 to reflect amortization of the reserve deficiencies.

48. It is appropriate to increase customer operations expense by $582 to reflect the adjustment made for message processing charges.

49. It is appropriate to reduce corporate operations expenses by $2,385 to reflect adjustments to legal fees incurred during the test year.

50. It is appropriate to remove $236 from plant nonspecific operations expense to reflect a decrease in power expense due to the removal from service of two remote units.

51. It is appropriate to exclude $3,374 of excess affiliated engineering charges from the Company's cost of service.

52. It is appropriate to normalize rate case expenses by allowing one-fifth of rate case expense in setting rates for this proceeding.

53. The appropriate total Company level of rate case expense for use in this proceeding is $68,336.

54. It is appropriate to apply the respective intrastate allocation factor to rate case expense.

55. It is appropriate to remove $1,770 from corporate operations expenses to reflect the removal of certain miscellaneous expenses.

56. The appropriate level of gross receipts tax under present rates is $160.

57. It is appropriate to decrease other taxes by $222 to reflect the proper regulatory fee amount.

58. It is appropriate to increase State income taxes by $3,882 to reflect the adjustments made to the Company's revenues and expenses.

59. It is appropriate to increase Federal income taxes by $15,712 to reflect the adjustments made to the Company's revenues and expenses.

60. The Applicant's reasonable level of test year operating revenue deductions after accounting, pro forma and end-of-period adjustments is $421,204.

61. The capital structure and cost rates reasonable and appropriate for use in this proceeding are:

Item	Percent	Embedded Cost
Long-term Debt	79.75%	5.00%
Common Equity	20.25%	12.25%

62. The combination of the appropriate capital structure and cost rates yields an overall rate of return of 6.47%.

63. Based on the foregoing, Saluda Mountain should be allowed to increase its annual level of gross operating revenues by $120,491. This increase would allow Saluda the opportunity to earn the 12.25% rate of return on common equity which the Commission has found just and reasonable. This increased revenue requirement is based on the Company's original cost rate base and its reasonable test year operating revenues and expenses as determined in the above findings of fact.

64. The appropriate intrastate interLATA billing and collection revenue requirement for use in this proceeding is $16,725.

65. The intrastate interLATA billing and collection rates should be increased to produce $2,157 in additional revenues.

66. It is not appropriate to change any of Saluda Mountain's intrastate interLATA access charges (except as noted in No. 65 above) as proposed by any party in this proceeding.

67. It is appropriate to eliminate zone charges.

68. The rates and charges contained in Appendix B, attached hereto, are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings of fact are based on the Company's verified application and the entire record. They are essentially informational, procedural and uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is found in the testimonies of the seven public witnesses who appeared at the hearing in Saluda, Company witness Owens and Public Staff witness Goetz.

Five of the seven public witnesses noted that they had seen significant improvement in the quality and reliability of their telephone service during the past few years. One witness commented that prior to the recent plant upgrades at Saluda, "you could expect out of a month to be out of a phone from three to five days, especially if there was a storm or a sleet storm in the winter." Another witness added that several years ago "our phone lines were down in the bushes. Every time it rained we had to go out and check the bushes to get them to work."

Of the two remaining witnesses, one was a newcomer to the area who had no experience with the telephone system in Saluda prior to TDS's acquisition of the Company. However, she expressed satisfaction with the present service, and noted that it had remained working through a terrible snow storm. One witness offered no comments about the quality of service provided.

In his testimony, Company witness Owens acknowledged that, prior to TDS's construction activities at Saluda Mountain, the quality of service was poor, as measured in terms of trouble indices, held orders for regrades and new service, and the condition, capabilities and reliability of central office equipment and outside plant was poorly constructed and maintained. He stated that the Company had "completely reworked or rebuilt all outside and inside plant." Among the improvements he cited were construction of approximately 160 route miles of new facilities, including a fiber facility for toll and Extended Area Service (EAS), rehabilitation of the remaining outside plant, redesign of the subscriber loop plant, installation of a DMS-10 digital switch in a new central office building, and implementation of improved maintenance and billing systems. Witness Owens described how these upgrades had improved Saluda Mountain's trouble index and held order performance and expressed his view that the Company's customers now had "state-of-the-art facilities" and "the same modern infrastructure found in urban areas."

During cross-examination by the Public Staff, witness Owens was questioned regarding held orders for service. Mr. Owens stated that the only held orders for new service at the time of the hearing related to mobile homes where installation was not possible because the homes were not yet in place.

Public Staff witness Goetz also described the plant improvements and provided test results and quality of service statistics documenting Saluda Mountain's past and present service performance. According to his testimony, in tests conducted by the Public Staff during 1993, Saluda Mountain satisfied the Commission's service objectives for call completions, transmission loss and trunk noise. The Company also met Commission standards for operator "0," directory assistance and business office/repair service answer time in Public Staff tests.

The Public Staff also tabulated statistics showing Saluda Mountain's performance in seven other service categories from October 1991 through mid-1993. For percentages of regular service orders completed within five working days and new service installation appointments not met for company reasons, Saluda Mountain consistently met Commission objectives; for percentages of out-of-service troubles cleared within 24 hours, the Company met these objectives for every month but one. Their statistics on initial and repeat customer trouble reports were more erratic, but these indices have gradually improved since October 1991, and have been consistently satisfactory since December 1992 for the initial reports and since October 1992 for the repeat reports.

Three areas of concern were raised by Public Staff witness Goetz. First, one paystation (representing 14% of the Company's complement of seven) was found to be out-of-order. According to witness Goetz, this unit is either being removed or replaced by semipublic service and apparently will not create an ongoing service problem. The Company has also reduced its regrade application held orders not completed within 30 days to 0.00% for May 1993, meeting the Commission objective. Finally, the testimony of Company witness Owens indicated that the number of held service orders was not a problem at the time of the hearing. According to witness Goetz, the Company had pledged to satisfy all Commission service objectives by July 1993.

Based on the foregoing considerations, the Commission concludes that the quality of service that Saluda Mountain provides to its customers is adequate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence concerning capital recovery changes is contained in the testimony and exhibits of Company witness Meade and Public Staff witness Sutton.

Regarding the prescription of new depreciation rates for Saluda, Company witness Meade and Public Staff witness Sutton proposed different depreciation rates. However, as witness Sutton pointed out, the Commission prescribed a new schedule of depreciation rates for Saluda at the May 10, 1993, Staff Conference with an effective date of April 1, 1993. Witness Sutton recommended that the Commission approved rates be used for the calculation of test year depreciation expenses and presented those rates in his Sutton Exhibit No. 1 under the column labeled "P S PROPOSED RATES". In its proposed order, the Company agreed with the use of these deprecation rates approved by the Commission.

Subsequently, in its June 11, 1993, filing to update certain items in the rate case, the Company proposed to establish two additional depreciation categories: Company Communications Equipment and Leasehold Improvements. The

Company recommended a rate of 7.9% for Company Communications Equipment and a rate of 2.5% for Leasehold Improvements. Witness Sutton concurred with the Company's proposals in this regard.

Based on the foregoing, the Commission concludes that the two additional rates proposed by the Company are reasonable and prescribes these proposed rates for the two additional categories. Further, the Commission affirms its decision at the May 10, 1993, Staff Conference in which it represcribed the depreciation rates for Saluda that are presented in Sutton Exhibit No. 1. The appropriate depreciation rates for Saluda are reflected in Appendix A, attached hereto.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-23

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witnesses Szczech, Goetz, and Sutton. The following schedule summarizes and compares the Company's rate base recommendation and the Public Staff's, as set forth in their proposed orders.

Item	Company	Public Staff	Difference
Telephone plant in service	$2,273,748	$2,273,748	$ 0
Accumulated depreciation	(189,040)	(189,040)	0
Net telephone plant	2,084,708	2,084,708	0
Working Capital:			
Cash	24,486	24,486	0
Materials and supplies	14,842	14,842	0
Average tax accruals	(4,770)	(4,770)	0
Total working capital	34,558	34,558	0
Deferred income taxes	(16,179)	(16,179)	0
Postretirement benefits	(2,880)	(2,880)	0
Unamortized CPE gain	(11,503)	(10,225)	1,278
Original cost rate base	$2,088,704	$2,089,982	$ 1,278

Plant in Service

The evidence concerning the proper level of telephone plant in service is found in the testimony of Company witness Meade and Public Staff witnesses Szczech, Sutton, and Goetz. Public Staff witness Szczech increased plant in service by $97,045 to reflect actual post-test year plant additions and by $1,255 to reflect capitalized legal fees incurred during the test year to secure capital leases. Public Staff witness Goetz proposed that Saluda Mountain be required to remove $67,392 of excess line card investment from plant in service. After applying an intrastate allocation factor of 66.94%, witness Goetz's excess line card investment adjustment resulted in the removal of $45,112 from the Company's intrastate plant in service.

At the hearing and in its proposed order, the Company did not disagree with any of these adjustments to plant in service or with the Public Staff's recommended level of telephone plant in service of $2,273,748.

Therefore, based on the foregoing, the Commission finds that the appropriate level of plant in service is $2,273,748.

Accumulated Depreciation

The evidence concerning the proper level of accumulated depreciation is found in the testimony and exhibits of Company witness Meade and Public Staff witnesses Szczech and Sutton.

Public Staff witness Szczech increased accumulated depreciation by $5,701 to reflect actual post-test year plant additions and decreased accumulated depreciation by $27,395 to reflect the actual plant retirements and cost of removal. The net adjustment resulted in a $21,694 decrease to the Company's intrastate accumulated depreciation. Witness Szczech also adjusted accumulated depreciation to include $34 related to capitalized legal fees and to remove $2,440 relating to the excess plant adjustment. The Company accepted these adjustments to accumulated depreciation in its proposed order.

Based on the foregoing, the Commission finds that it is appropriate to decrease accumulated depreciation by $21,694 to reflect actual post-test year plant additions, increase accumulated depreciation by $34 to reflect capitalized legal fees, and decrease accumulated depreciation by $2,440 to reflect removal of excess plant.

Public Staff witness Sutton recommended increasing Saluda's depreciation reserve balance by $5,506 to reflect the completed amortization of Customer Premises Wiring (CPW). In 1981 this Commission issued an Order requiring Saluda, and all other regulated telephone companies that selected the "flash-cut" option, to complete the amortization of CPW by September 30, 1991. By its letter dated August 25, 1981, Saluda agreed to complete the amortization of all of its CPW on or before that date. Applying the intrastate allocation factor to $5,506, witness Szczech determined $3,986 to be the appropriate amount to increase the Company's depreciation reserve. Witness Szczech also decreased accumulated depreciation by $2,942 to reflect the Public Staff's recommended depreciation rates and end-of-period depreciation expense which the Commission has found reasonable herein. The Company accepted these adjustments in its proposed order.

The Commission finds that it is appropriate to increase accumulated depreciation by $3,986 to reflect the completed amortization of CPW. Additionally, the Commission also finds that it is appropriate to decrease accumulated depreciation by $2,942 to reflect the depreciation rates prescribed and approved by the Commission.

In his original direct testimony, Company witness Meade identified a reserve deficiency of $59,542 associated with the COE Step-by-Step Switching account and a reserve deficiency of $36,345 associated with the Aerial Wire account. He proposed amortizing these deficiencies over a 10-year period. Public Staff witness Sutton agreed with Mr. Meade's proposed treatment and amortization period, but recommended adjusting the amortization amounts to reflect the results of a company-conducted inventory in May of 1993. According to Mr. Sutton, that inventory indicated the reserve deficiency for the COE Step-by-Step Switching account to be $60,070 and the reserve deficiency for the Aerial Wire account to be $46,652. The Company's original filing did not reflect the increases in accumulated depreciation related to the Company's proposed amortization of these reserve deficiencies of $5,954 and $3,635. Therefore, the Public Staff increased the intrastate accumulated depreciation by $4,349 to reflect amortization of the actual May 1993 COE Step-by-Step reserve deficiency and by $3,377 to reflect amortization of the actual May 1993 Aerial Wire reserve deficiency. In addition, Witness Sutton stated in his prefiled testimony that Other Work Equipment reflected a reserve deficiency of $527 which he recommended be amortized over a 10-year period. Therefore, the Public Staff increased accumulated depreciation by $38. The Company in its proposed order accepted the adjusted reserve deficiencies proposed by the Public Staff.

Based on the foregoing, the Commission finds that the 10-year amortization period for the reserve deficiencies is appropriate. In addition, the Commission finds that the May 1993 deficiency balances should be reflected. Therefore, the Commission finds that it is appropriate to increase accumulated depreciation by $7,764 to reflect the amortization of these deficiencies.

In its proposed order, the Company agreed with the Public Staff's recommended level of accumulated depreciation of $189,040.

Based on the foregoing, the Commission finds that the appropriate level of accumulated depreciation is $189,040.

Working Capital

The evidence concerning the proper level of working capital is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech. The Company and the Public Staff agreed on the appropriate level of materials and supplies of $14,842 and average tax accruals of $4,770. The parties also agreed on the methodology of calculating cash working capital as one-twelfth of operating expenses excluding depreciation.

The Commission, therefore, finds that the appropriate level of materials and supplies is $14,842 and the appropriate level of average tax accruals is $4,770. The Commission also finds that the appropriate level of cash working capital is $24,947 based on the level of operating expenses less depreciation the Commission has found reasonable and appropriate in this proceeding.

Accumulated Deferred Income Taxes

The evidence concerning the proper level of accumulated deferred income taxes is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech. In its proposed order, the Company agreed with the Public Staff's recommended level of accumulated deferred income taxes.

Therefore, based on the foregoing, the Commission finds that the appropriate level of accumulated deferred income taxes is $16,179.

Postretirement Benefits

The evidence concerning the proper level of unfunded postretirement benefits to be deducted from rate base is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech. The Public Staff agreed with the adjustment to postretirement benefits as proposed by the Company in its application.

Therefore, based on the foregoing, the Commission finds that it is appropriate to reduce rate base by $2,880 to reflect unfunded postretirement benefits.

Unamortized CPE Gain

The evidence concerning the deduction of the unamortized CPE gain from rate base is found in the testimony of Company witness Meade and the testimony and exhibits of Public Staff witness Szczech. The Company did not disagree with the removal of the unamortized portion of the CPE gain from rate base, but did disagree with the period in which to flow the gain back to Saluda's ratepayers.

The parties are in disagreement over the proper period to flow back the CPE gain. The Company proposed a 10-year period while the Public Staff recommended a five-year period. The total amount of the CPE gain is $20,993; $12,781 is the net-of-tax amount that the parties have agreed to flow back to the ratepayers. Public Staff witness Szczech testified that a five-year period to flow back the CPE gain to Saluda's ratepayers is reasonable for purposes of this proceeding. Thus, witness Szczech is recommending that $10,225, representing the unamortized net-of-tax balance be included as a reduction to rate base. Witness Meade testified that a 10-year amortization period is more appropriate since this would return the gain over a period that approximates the life of the asset that gave rise to this gain. Witness Meade recommended that an amount of $11,503 representing the unamortized net-of-tax balance be included as a reduction to rate base in this proceeding.

Ms. Szczech testified that Saluda has had the use of this money, cost-free, since 1988, and during cross-examination, Company witness Meade agreed with this fact. Mr. Meade further agreed that the Commission's Order in Docket No. P-100, Sub 81, which allowed the deregulation of CPE on December 31, 1987, does not state that the gain should be flowed back over the life of the related assets, as proposed by the Company. In addition, witness Meade stated that he was not aware of any prior telephone cases where the amortization period of the gain was tied to the life of the CPE. Finally, Witness Meade agreed, subject to check, that the Commission adopted a five-year period to flow the CPE gain back to the ratepayers in Citizens Telephone Company's (Citizens) last general rate case proceeding, Docket No. P-12, Sub 89, and adopted a four-year period in Ellerbe Telephone Company's (Ellerbe) last general rate case proceeding, Docket No. P-21, Sub 54.

Additionally, the parties also proposed CPE related adjustments to the level of miscellaneous revenues under present rates. The Public Staff increased the level of miscellaneous revenues by $4,199 to reflect its proposed five-year amortization of the $20,993 CPE gain, and the Company made a corresponding adjustment of $2,099 to reflect its proposed 10-year amortization of the $20,993 CPE gain, thus a difference of $2,100 results between the parties' regarding the proper level of miscellaneous revenues.

The Commission, upon examination of all the evidence in the record in this docket, finds that it is reasonable and appropriate to flow the CPE gain back to Saluda's ratepayers over a five-year period. The Commission does not agree with the Company's proposed correlation between the life of the CPE and the appropriate period to flow that gain back to ratepayers. The Commission recognizes that the Company has had the use of these funds cost-free since 1988.

Additionally, the use of a five-year period seems fair and reasonable in view of other decisions which the Commission has reached in this proceeding with regard to proper amortization periods. Therefore, the Commission finds that rate base should include a deduction for the unamortized CPE gain in the amount of $10,225 to recognize a five-year flow back period for the net-of-tax CPE gain. The Commission also finds that miscellaneous revenues under present rates as proposed by the Company should be increased by $2,100 to reflect the annual level of such amortization over five-years.

Based on the foregoing, the Commission finds that the appropriate original cost rate base used and useful for use in setting rates in this proceeding is $2,090,443, as shown in the following schedule:

Item	Amount
Telephone plant in service	$2,273,748
Accumulated depreciation	(189,040)
Net telephone plant	2,084,708
Working capital:	
Cash	24,947
Materials and supplies	14,842
Average tax accruals	(4,770)
Total working capital	35,019
Deferred income taxes	(16,179)
Postretirement benefits	(2,880)
Unamortized CPE gain	(10,225)
Original cost rate base	$2,090,443

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-35

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witnesses Szczech, Garrison, and Willis. The following schedule presents the final positions of the parties on the proper amount of end-of-period net operating revenues as reflected in their respective proposed orders.

Item	Company	Public Staff	Difference
Local service	$123,122	$135,884	$12,762
Network access	64,974	64,974	0
Universal Service Fund	106,859	143,611	36,752
Long distance	116,316	116,316	0
Miscellaneous	35,711	37,811	2,100
Uncollectibles	(2,969)	(3,183)	(214)
Total operating revenues	$444,013	$495,413	$51,400

Local Service Revenues

The evidence regarding this matter is found in the testimony and exhibits of Company witness Meade and Public Staff witness Willis. The difference between the parties of $12,762 is due entirely to their differing opinions as to the proper level of revenues arising from touchtone service and custom calling offerings. The Public Staff recommended that the test year levels of local service revenues for touchtone services be adjusted by $9,519 and by $9,142 for custom calling offerings, whereas the Company made adjustments of $3,358 and $2,541, respectively.

Public Staff witness Willis proposed an adjustment to end-of-period local service revenues to reflect what he believed would be a reasonable level of revenue associated with relatively new service offerings (i.e., touchtone and custom calling) for Saluda subscribers. In his calculations to approximate a reasonable ongoing revenue level for these services, witness Willis used the average penetration level (88.81%) of North Carolina telephone companies, resulting from input data during the time period from December 1992 to March 1993 for touchtone service and the penetration level (56.52%) of Barnardsville Telephone Company at March 1993 for custom calling features. Public Staff witness Willis indicated that he believed it was reasonable to expect the percentage of subscriber lines with these services to approach or exceed the average penetration of other companies in North Carolina within "a relatively short period of time." Public Staff witness Willis further indicated that he believed the adjustment was necessary so that the revenues under present rates would more closely match the plant investment which is already in service.

Further, witness Willis stated that prior to the cutover of Saluda's new digital switch, the Company did not offer touchtone or custom calling features. Mr. Willis testified that since the capability is inherent in the new switch, the Company gained the capability to offer these services with the cutover and began offering them on April 29, 1992. He stated that since that time only a small number of customers have subscribed to these services, though the number of units has grown rapidly since the cutover.

Witness Willis testified that he had proposed this adjustment to keep the Company's customers from paying for custom calling features and touchtone service twice. Witness Willis stated that, since the cost of providing these services is already in rate base, unless the level of end-of-period revenues is adjusted to reflect a reasonable level of revenues from these services, the basic rates would be set to fully recover the remaining cost of these services. He testified that with each new unit of service added after the test period, the Company would collect additional revenue for which it had no additional cost and that if other things were held constant, this would increase the Company's return above its authorized level. Witness Willis stated that the Company's rates for these services are well below those of most other companies in North Carolina and that in his opinion it is reasonable to expect the percentage of subscriber lines with these services to approach or exceed the average penetration of other companies in this State in a relatively short time. Mr. Willis stated that he used the average penetration level for North Carolina to calculate his adjustment for touchtone calling revenues, but used the penetration level for Barnardsville Telephone Company in his calculation of the adjustment for custom calling features since the state average penetration level for North Carolina was not available for custom calling features.

During cross-examination by the Company, witness Willis was questioned regarding whether Saluda Mountain would have the revenue from custom calling features proposed by him in the year after the rates in this case became effective. Mr. Willis answered no, but indicated that the Company could have that amount of revenue or even more in several years. Mr. Willis further explained that if the level of penetration at the end of the test period were used, the remaining customers would pay for this service both in their basic rate and in the future when they subscribe to these services. Mr. Willis testified that he wanted to keep this from happening by making an adjustment that will reduce the Company's immediate revenues, but will provide those revenues over time. When asked if the Company would have the revenues proposed by him for touchtone calling during the year after the rates become effective, Mr. Willis agreed that the Company would not, but stated that the present worth of the future stream of revenues should exceed this.

The revenue level used by witness Meade in his original testimony and exhibits reflected the Company's penetration levels for custom calling and touchtone features at the end of December 1992, eight months after the features were initially introduced. However, at the hearing, the Company conceded that an adjustment of its touchtone calling and custom calling revenue based on the annualization of its actual levels of penetration (45.39% for touchtone and 23.18% for custom calling) as of July 1993 was reasonable and this was the final position taken by the Company in its proposed order.

Company witness Meade in his rebuttal testimony stated that Mr. Willis' adjustments were inappropriate for two reasons. Witness Meade testified that it had taken Barnardsville Telephone Company nearly six years to reach the penetration levels advocated by witness Willis and stated that it is unreasonable to suggest that Saluda Mountain will recognize the level of revenue proposed by the Public Staff in the year after these rates become effective. Witness Meade also took exception to the use of the statewide average for touchtone penetration. He stated that such average is skewed because it incorporates the penetration levels of Southern Bell (96.18%) and other large companies and includes companies that have offered this service for many years and have developed their penetration levels over a long period of time. He stated that these penetration levels are unrepresentative of the Company's current penetration levels or levels that the Company can reasonably hope to achieve in the near future.

Although witness Meade agreed that touchtone and custom calling features are a part of the new digital switch which is going to be included in rate base, he did not agree that under the Company's proposal future subscribers would be paying for the features twice. He stated that it is the Company's position that current customers will benefit because the provision of these services in the future would prevent the Company from coming back for another rate case as soon. Witness Meade testified that if the switch had just been placed into service and no customers had subscribed to touchtone and custom calling features, the Company would agree to impute a reasonable level of expected revenue in the next year or so, but not full penetration.

The Commission finds good cause to adopt the annualized levels of revenues for touchtone and custom calling services agreed to by the Company during the hearing which reflect the penetration levels actually achieved for those services as of July 1993, and to reject as unreasonable the revenue adjustments for those services proposed by the Public Staff. The revenue adjustments proposed by the Public Staff are based on levels of penetration for the services in question which have been attained by other telephone companies only after years of marketing. By comparison, Saluda Mountain has only offered touchtone and custom calling services since April 1992. The levels of penetration advocated by the Public Staff would be unreasonable for Saluda Mountain at this time and would, in essence, ignore the Company's unique situation and circumstances. That being the case, it is reasonable and appropriate to adjust the Company's revenues to reflect an annualized level for touchtone and custom calling services based on the actual levels of penetration for those services attained at the time of the hearing in this case, some nine months after the close of the test year and 15 months after the features were initially introduced.

Finally, Public Staff witness Willis stated in prefiled testimony that the Company had overstated end-of-period local service revenues by $841 for public telephone coin revenues. Mr. Willis stated that it is appropriate to reduce his adjustment to local service revenues by $841 to correct this overstatement. The Company's final position in its proposed order on the proper level of local service revenues indicated that it was in agreement with the Public Staff in regard to the level of public telephone coin revenues. Therefore, the Commission accepts the parties' proposed level of public telephone coin revenues.

Based upon the foregoing, the Commission concludes that end-of-period local service revenues should be increased by $3,358 for the Company's adjustment to touchtone revenues and $2,541 for the Company's adjustment to custom calling revenues to reflect the annualization of these revenues to the Company's July 1993 penetration levels. Thus, the Commission finds that the proper level of end-of-period local service revenues to be reflected in the cost of service in this proceeding is $123,122 under present rates.

Network Access Revenues

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witness Garrison.

Mr. Garrison testified that he had reviewed the end-of-period interLATA network access revenue adjustments made by Saluda Mountain and that he found them to be reasonable. Further, he recommended that no adjustment be made to the Company's amounts. No party to the proceeding contested the end-of-period amounts used by Saluda Mountain or the Public Staff for interLATA network access revenues and the Commission concludes that these amounts are reasonable and appropriate to use in this proceeding.

Universal Service Fund (USF) Revenues

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witnesses Szczech and Garrison as well as the Evidence and Conclusions for Findings of Fact Nos. 23 and 60.

Witness Meade testified that the $127,212 amount of USF adjusted test year revenues submitted by Saluda Mountain in its original application was incorrect and should be revised to $106,859. According to witness Meade's testimony on rebuttal, this USF revenue revision was done to reflect that the Company's actual level of income taxes would be a negative $65,012 at September 30, 1993. However, the testimony in this case is conflicting as to what the Company's amount of USF revenues represents. Mr. Meade testified at one point that the original $127,212 amount supported by the Company represents the annualized amount Saluda Mountain is to receive in the third and fourth quarters of 1993. However, he later stated that the Company's corrected amount of $106,859 reflects what Saluda Mountain will receive for the twelve months beginning in July 1994.

Witness Meade also testified that Saluda Mountain had filed to recover $96,486 in USF revenues for the period ended March 1993 and would begin receiving these revenues in January 1994. Thus, the time period over which Saluda Mountain's calculated USF revenues will be received is uncertain.

Public Staff witness Garrison testified that his calculation of USF revenues was determined using the same method as Saluda Mountain. His testimony on this point was not challenged or contested by Saluda Mountain. Witness Garrison testified that his proposed level of USF revenues was $143,611 and reflected the end-of-period adjustments recommended by the Public Staff except that his calculation only reflected one-half of the depreciation expense adjustment which was in accordance with the Company's methodology and reflected a zero level of income taxes. Mr. Garrison testified that his USF revenue calculation was not intended to match a certain time period, but was made to reflect an ongoing level of USF revenues using the end-of-period adjustments made by the Public Staff. Further, Mr. Garrison testified that the basis for using zero income taxes was to recognize the current negative income tax liability and the future positive income tax liability that the Company is expected to have sometime after its rate increase. Including only one-half of the depreciation expense adjustment was done to balance the current and future depreciation expense level and to recognize that the depreciation expense included in this rate case will not be all forthcoming in a one-year period considering the filing cycle with the National Exchange Carrier's Association (NECA), the administrator for USF revenues. Mr. Garrison further testified that once all of the revenues, investment, and expenses included in this case are reflected on the Company's books, Saluda Mountain's USF revenues will be approximately $200,000.

The methodology used by Saluda Mountain was generally one of using its end-of-period adjustments in this case and projecting the USF revenues which would be obtained if those end-of-period adjustments were reflected on the Company's books except that a negative $65,012 in income taxes and only one-half of the depreciation expense adjustment were reflected in Saluda Mountain's calculation. The rebuttal testimony of witness Meade indicates that only the level of income taxes was changed in coming up with his revised level of USF revenues of $106,859. Thus, the revised level of USF revenues recommended by Saluda Mountain do not appear to reflect any of the Public Staff's adjustments to expenses and investment which were accepted by the Company.

Another issue regarding the Company's calculation is whether its level of income taxes was estimated correctly. Mr. Garrison testified that he had questions regarding Saluda Mountain's calculation of its estimated income taxes. Additionally as noted, the Company's revised USF revenue calculation fails to reflect the end-of-period expenses and investment which it recommended in this case and, further, the Commission is unsure that Saluda Mountain's estimate of negative income taxes is correct.

Based upon the evidence, the Commission recognizes that the Public Staff's USF revenue calculation reflects the end-of-period investment and expenses which it recommended except for its proposed levels of income taxes and depreciation expense. Therefore, the Commission believes it would be proper to accept the Public Staff's USF revenue level as the starting point for determining the level of USF revenues to include in this proceeding. Further, the Commission believes that including zero income taxes and one-half of the depreciation expense adjustment, as proposed by the Public Staff, is a reasonable way to produce an ongoing level of USF revenues for purposes of this case. Using the data filed by the Public Staff on September 8, 1993, in response to the September 2, 1993, data request issued by the Commission and recognizing the conclusions which the Commission has made and discussed elsewhere herein, the Commission concludes that the proper level of USF revenues to be included in this proceeding is $147,340. Based upon the Public Staff's testimony, the Commission notes that once all of the adjustments made in this case are reflected on the Company's books, its USF revenues will be approximately $200,000. Thus, the Commission finds that reflecting USF revenues of $147,340 is a reasonable approximation of the ongoing level to include in this case.

IntraLATA Long Distance Revenues

The evidence concerning this finding of fact is found in the testimony of Company witness Meade and Public Staff witness Garrison. The Company and the Public Staff agreed on the appropriate level of intraLATA long distance revenues.

Based on the foregoing, the Commission finds that the appropriate level of intraLATA long distance revenues is $116,316.

Miscellaneous Revenues

The evidence concerning this finding of fact is found in the testimony of Company witness Meade and Public Staff witness Garrison. The Company and the Public Staff agreed on the appropriate levels of interLATA billing and collection revenues of $14,568; directory revenues which included an end-of-period adjustment of $5,564; pole rental revenues which included an end-of-period adjustment of $153; and all other miscellaneous revenues except the revenues associated with the CPE gain which was previously discussed in the Evidence and Conclusions for Finding of Fact No. 22. The only difference between the parties in the amount of $2,100 is due entirely to the difference in amortization periods of the CPE gain. As previously discussed, the Company proposed a 10-year amortization period and the Public Staff proposed a five-year amortization period and the Commission has agreed with the Public Staff that an adjustment of $2,100 is appropriate to recognize a five-year amortization of the flow back of the CPE gain. Thus, the Commission finds that the appropriate level of miscellaneous revenues under present rates is $37,811, for purposes of this proceeding.

Uncollectibles

Public Staff witness Szczech adjusted uncollectibles by applying the Company's rate of 1.67% to the Public Staff's adjustments to local service revenues. This calculation caused the Public Staff's level of uncollectibles to be $214 higher than the Company's. As discussed previously herein, the Commission agreed with the Company's calculation of local service revenues under present rates and thus concludes that the appropriate level of uncollectibles is $2,969, for use in this proceeding.

Based upon the foregoing, the Commission finds that the appropriate level of end-of-period net operating revenues is $486,594, as shown in the following schedule:

Item	Amount
Local service	$123,122
Network access	64,974
Universal Service Fund	147,340
Long distance	116,316
Miscellaneous	37,811
Uncollectibles	(2,969)
Total operating revenues	$486,594

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 36-60

The evidence concerning these findings of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witnesses Szczech, Goetz, Sutton and Garrison. The following schedule summarizes and compares the Company's and the Public Staff's recommendations on the proper level of operating revenue deductions, as set forth in their proposed orders.

Item	Company	Public Staff	Difference
Plant specific operations	$ 79,908	$ 76,649	$ (3,259)
Depreciation and amortization	135,932	135,932	0
Plant nonspecific operations	26,051	25,813	(238)
Customer operations	79,840	79,269	(571)
Corporate operations	114,971	105,973	(8,998)
Nonincome taxes/other oper. exp.	6,127	6,127	0
Total O&M Expenses	442,829	429,763	(13,066)
Gross receipts tax	160	564	404
Other taxes	(222)	(222)	0
State income tax	(6,663)	(1,698)	4,965
Federal income tax	(26,965)	(6,871)	20,094
Total operating revenue deductions	$409,139	$421,536	$ 12,397

Payroll, Payroll Taxes and Benefits, and Rent Expense

The evidence concerning these findings of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech. In its proposed order, the Company agreed with the adjustments recommended by the Public Staff to increase operating expenses by $1,200 to reflect actual salary levels as of July 1, 1993, and to also make a corresponding adjustment of $204 to update payroll taxes and benefits to the same time period. Additionally, the Company accepted the Public Staff's adjustment to remove $3,784 for central office building rent expense that is no longer being incurred.

Therefore, the Commission finds that the adjustments to payroll, payroll taxes and benefits and rent expense and the resulting amounts are reasonable and proper for use in this proceeding.

Training

The evidence concerning the findings of fact regarding training expense is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech.

In her prefiled testimony, Public Staff witness Szczech stated that two adjustments to training expense (plant specific operations) are appropriate in this proceeding. Witness Szczech recommended that the intrastate expense amount of $1,840 incurred for the training of a Barnardsville Telephone Company employee on the Northern Telecom DMS-10 switch at Saluda should be removed from Saluda's cost of service. Ms. Szczech testified that Saluda's ratepayers have not received any benefit from this training and if and when this employee is needed to work on the switch, his time plus loadings will be billed to Saluda. Therefore, in witness Szczech's opinion the ratepayers would, in effect, be paying twice for this service. Ms. Szczech also testified that the Barnardsville employee, with the training received on the DMS-10 switch, would be available to work on switches at other Local Exchange Companies (LECs) within the TDS system. Ms. Szczech testified that there are eight TDS LECs within Tennessee alone with a Northern Telecom DMS-10 switch.

Public Staff witness Szczech also recommended normalizing the level of training expense incurred for Saluda employees by allowing only one-fifth of the Company's intrastate test year level of $1,697 on an ongoing basis. Therefore, witness Szczech included $339 in the Company's cost of service to cover annual training expenses for the Company's three full-time employees. Witness Szczech testified that an abnormally high level of training occurred during the test year due to the new systems in place at Saluda and that this level of training could not reasonably be expected to occur every year in the future and therefore she recommended the five-year amortization of these costs.

Saluda Mountain witness Meade included the intrastate expense amount of $1,840 for training the Barnardsville employee and testified that the Barnardsville employee was trained on the Saluda Mountain digital switch as an emergency backup. Further, witness Meade testified that the knowledge gained by this person can only be used in working on the Saluda Mountain switch and cannot be used at Barnardsville, as that Company has a different switch. Accordingly, the training of this Barnardsville employee has value only for Saluda Mountain and should properly be viewed as an insurance policy on the Company's switch. Witness Meade further testified that it is certainly responsible, and of benefit to the Company's customers, to have someone other than the one trained Company employee available to maintain the switch if the need arises. The Company perceives itself to be in a situation where this training expense is being challenged, yet it would be questioned on the lack of availability of any emergency backup if the need arose due to unforeseen circumstances.

Further, witness Meade testified that the Public Staff's five-year amortization adjustment which reduces the level of Saluda employees' training expense by $1,358 is arbitrary. According to witness Meade, the Public Staff's position, in effect, penalizes the Company for being committed to providing an ongoing training program. Witness Meade testified that Saluda Mountain commits its employees to at least 40 hours of training per year and this training may deal with central office equipment, outside plant, safety, customer service, and industry and community issues such as E911. The Company believes that its $1,697 level of training expense for Saluda employees is reasonable and should be allowed considering TDS's commitment to the development of Saluda's employees and the provision of quality customer service.

Based on the foregoing, the Commission concludes that it is appropriate to reject the ratemaking adjustments to training expense proposed by the Public

Staff. The Commission will, however, amortize the training costs of $1,840 associated with the Barnardsville employee over a period of five years rather than including the full amount in the cost of service as requested by the Company. Saluda Mountain is a small telephone company, with only three full-time employees. The Company's decision to incur the expense of training the Barnardsville employee as a backup maintenance person on the Saluda Mountain switch was reasonable and prudent under the circumstances. It is a reasonable way of insuring that its customers will not have to wait for service while a qualified person can be located in another state and brought to Saluda Mountain. That being the case, it is appropriate to amortize the training expense in question over a period of five years and to include the amount so amortized in the cost of service.

Furthermore, it is reasonable and appropriate to include the Company's entire amount of its employee test year intrastate training expense of $1,697 in the cost of service. The Public Staff proposes to include only $339 to cover all intrastate expenses of training Saluda's three full-time employees each year. Such amount would be insufficient to allow Saluda Mountain to provide each of its three employees with at least 40 hours of training each year in conformity with its corporate policy and goals regarding employee training. The Commission fully supports the Company's policy on employee training considering the unique situation and circumstances of Saluda's operations. Therefore, the Commission finds the Company's amount of training expense to be a reasonable level for inclusion in this proceeding.

Pole Rental Expense

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech. The Company in its proposed order agreed with the Public Staff's recommended adjustment of $5,165 to pole rental expense.

There being no evidence to the contrary, the Commission concludes that it is appropriate to increase test year expenses by $5,165 for pole rental.

Affiliated Charges

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech.

Public Staff witness Szczech testified that she removed from the Company's cost of service an intrastate amount of $8,745 for TDS affiliated charges which she determined to be unreasonable. Ms. Szczech testified that it was her understanding that these charges were billed out on a "per access line" basis; therefore, the charges should be comparable between the North Carolina TDS LECs (Saluda, Barnardsville and Service Telephone Company). Ms. Szczech stated that in analyzing these charges on a per access line basis, it is apparent that Saluda received an unreasonable level of these affiliated charges during the test year. Therefore, witness Szczech removed the excess affiliated charges from Saluda's cost of service. On cross-examination, witness Szczech testified that the TDS affiliated charges were actual expenses during the test year, but she stated if they were on a per access line basis, they should have never been billed to Saluda and they were unreasonably high.

Company witness Meade testified that the information presented to the Public Staff for TDS affiliated charges represents direct charges to Saluda, in addition to charges billed out on a "per access line" basis. Mr. Meade further stated that Saluda received a higher portion than normal of affiliated charges during the test year due to the massive construction project at Saluda. Therefore, he testified, it is appropriate to amortize these affiliated charges over a five-year period as Public Staff witness Goetz recommended for excess affiliated engineering charges.

Public Staff witness Szczech argued that Mr. Goetz had identified specific affiliated engineering charges that were related to the construction at Saluda and recommended amortizing those charges over a five-year period, while Ms. Szczech had not identified specific charges. Therefore, Ms. Szczech testified, it would not be appropriate to amortize the excess affiliated charges.

Based on the foregoing, the Commission finds that it is appropriate to amortize the TDS affiliated charges of $8,745 in question over a period of five years and to include the amount of $1,750 so amortized in the cost of service. This ratemaking treatment is consistent with our decision, set forth below, to amortize certain affiliated engineering charges over a period of five years. We find credible witness Meade's testimony that Saluda Mountain received a higher proportion of affiliated charges during the test year due to its massive construction program. That testimony supports amortization of the costs in question over a period of five years and rejection of the Public Staff's proposed adjustment. The Commission adjustment of $1,750 is distributed to the various categories of expense as follows: $61 is included in plant specific operations, $238 is included in plant nonspecific operations, $571 is included in customer operations, and $880 is included in corporate operations.

<u>Depreciation Expense, Message Processing Charges, and Legal Fees</u>

The evidence concerning these findings of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witness Szczech. In its proposed order, the Company agreed with the following adjustments recommended by the Public Staff: (1) increase depreciation and amortization expense by $5,098 to reflect one year of depreciation on the actual post-test year plant additions; (2) increase depreciation and amortization expense by $30 to reflect one year of amortization on the capitalized legal fees; (3) decrease depreciation and amortization expense by $2,444 to reflect the removal of excess line card investment; (4) decrease depreciation and amortization expense by $2,631 to reflect the end-of-period level of depreciation expense; (5) increase depreciation and amortization expense by $735 to reflect amortization of the reserve deficiencies; (6) increase customer operations expense by $582 to reflect the adjustment made for message processing charges; and (7) reduce corporate operations expenses by $2,385 to reflect adjustments to legal fees incurred during the test year.

Therefore, based on the foregoing, the Commission finds that the Public Staff's adjustments to depreciation expense, message processing charges, and legal fees are appropriate in this proceeding.

Power Expense

Public Staff witness Goetz recommended in his prefiled testimony the removal of $352 from test-year expenses for power to two remote sites that were removed from service in April, 1993. After application of the intrastate allocation factor, $236 should be removed from intrastate operating revenue deductions. The Company accepted this adjustment in its proposed order.

Based on the foregoing, the Commission finds that it is appropriate to remove $236 from operating expenses for the adjustment to power.

Affiliated Engineering Charges

Witness Goetz testified that the affiliated engineering charges booked during the test year were higher than Saluda Mountain would normally experience. These affiliated engineering charges were associated with Saluda's massive outside plant upgrade program and thus witness Goetz concluded that he did not expect an ongoing need for this level of engineering services. Therefore, he recommended amortizing these charges, amounting to $6,302, over a five-year period. After applying the appropriate intrastate allocation factor, $3,374 of excess affiliated engineering charges should be removed from intrastate operating revenue deductions. The Company accepted the Public Staff's recommendation in this regard.

Based on the foregoing, the Commission finds that it is appropriate to remove $3,374 of excess affiliated engineering charges from the Company's cost of service.

Rate Case Expense

The evidence concerning the findings of fact regarding rate case expense is found in the testimony and exhibits of Company witness Meade and Public Staff witnesses Szczech and Garrison and Public Staff Meade Rebuttal Cross-Examination Exhibit No. 1.

Company witness Meade proposed a three-year amortization period for rate case expense. The Company took the position that it is likely that it will have another rate case in three years due to uncertainties like future health care costs, depooling of toll revenues, future EAS costs and other structural changes in the telephone industry such as local competition.

The Public Staff recommended normalizing rate case expense by allowing one-fifth of the amount in operating revenue deductions. Witness Szczech stated in her testimony that based on an examination of the rate case filing cycle of other North Carolina LECs, Saluda Mountain (35 years since last rate case), and other LECs in the TDS system, a five-year amortization period is more than reasonable for this proceeding. Witness Szczech also stated on cross-examination that the Commission adopted a five-year amortization period in Citizens Telephone Company's last rate case, while a four-year period was used in Ellerbe Telephone Company's last rate case, which was a stipulated case with the amortization period being the result of negotiation. Finally, as Company witness Meade agreed on cross-examination, Saluda's rate case was driven by a massive construction project at Saluda to install a state-of-the-art system that Mr. Meade stated would hopefully be in place for 10 to 15 years.

Based on the foregoing, the Commission finds that it is appropriate to normalize rate case expense by allowing one-fifth of the amount found reasonable in this proceeding for purposes of calculating the Company's revenue requirement. The amortization period ordered is comparable to the amortization period ordered in previous LEC rate cases and reasonable when compared to the length of time historically between LEC rate cases in North Carolina.

In addition, the Company and the Public Staff disagreed on the level of rate case expense to be used in this proceeding. The Public Staff recommended $52,836. The Company maintained that $15,500 of additional rate case expense should be recognized which would result in a total amount of $68,336. Witness Szczech testified that based on an analysis of the two most recent telephone cases, the level recommended by the Public Staff in this proceeding is reasonable. Ms. Szczech testified that in Citizens' last rate proceeding, rate case expense was determined to be $67,000. Witness Szczech further testified that $20,000 of Citizens' rate case expense was for a cost of capital witness. In addition, Ms. Szczech testified that Citizens incurred costs for an outside consultant which Saluda has not incurred in this case. Public Staff witness Szczech testified that in Ellerbe's last rate case proceeding, rate case expense was determined to be $75,000; however, Ellerbe had to hire an outside consultant to put its rate case together. Finally, witness Szczech testified that the Company has failed to provide any supporting documentation for the additional increase in rate case expense, and that the Public Staff would question the reasonableness of any additional amounts.

Although witness Meade conceded that $52,836 was the correct total of rate case expense actually incurred by Saluda through May 15, 1993, he pointed out that such sum did not include amounts for the Company's cost of responding to Public Staff data requests after May 15, traveling to Raleigh to meet with the Public Staff in an effort to resolve other outstanding issues in this case, for attending the public hearing held in Saluda, preparation for and attending the hearing in Raleigh, or preparing the Company's proposed order and brief. Based upon those additional expenses, the Company updated rate case expense in its rebuttal testimony to reflect a revised total rate case expense of $68,336. The Company asserts that its rate case expense, as updated, is less than the amount of rate case expense included in the last two independent telephone company rate cases decided by this Commission and that its proposed level is reasonable under the circumstances.

Based on the foregoing, the Commission finds that the level of rate case expense recommended by Saluda Mountain of $68,336 is a reasonable level to include in this proceeding. In reaching that decision, the Commission found witness Meade's testimony in support of the Company's position to be persuasive and credible. It is entirely reasonable to update rate case expenses for expenses incurred or reasonably expected to be incurred after May 15, 1993, in conjunction with prosecution of this case so long as the amounts in question are reasonable. The Company has carried the burden of proof on this issue and has justified the amount of its rate case expense to the satisfaction of the Commission.

Finally, the parties disagreed as to whether an intrastate allocation factor should be applied to rate case expense. During cross-examination, Company witness Meade agreed that rate case expenses are properly classified as corporate operations expenses. The Public Staff presented Public Staff Meade Rebuttal

Cross-Examination Exhibit No. 1, which is a copy of annotated Federal Communications Commission (FCC) rules compiled by the NECA. This exhibit shows that corporate operations expenses are included in accounts 6710 and 6720 and that the expenses in these accounts, other than the extended area service expenses, are apportioned among the operations on the basis of the cost of the big three expenses - plant specific expenses, plant nonspecific expenses and customer operations expenses. Mr. Meade contended however that the rate case expense would be directly assigned to the intrastate jurisdiction and none of it would flow to the interstate. Mr. Meade's contention was refuted by Public Staff witness Garrison who testified that under the FCC's rules and regulations it would not be proper to directly assign the rate case expense to the intrastate jurisdiction. The Public Staff offered Exhibit JTG-2, a letter of interpretation issued in August of 1991 by the Common Carrier Bureau of the FCC in support of Mr. Garrison's position. Mr. Garrison further testified that in a Memorandum Opinion and Order that was adopted February 12, 1993, and released on March 3, 1993, the FCC concluded that the letter (Exhibit JTG-2) was correct. Essentially, if the FCC rules do not specifically state that direct assignment should be used, then the allocation procedures should be used instead.

Public Staff witness Szczech testified that in the last four telephone rate cases for a cost company, the Commission concluded that it was appropriate to apply an intrastate allocation factor to rate case expense.

In its proposed order and brief, Saluda Mountain changed its position regarding this issue and now concurs in the position taken by the Public Staff that it is appropriate to apply an intrastate allocation factor to rate case expense.

Based on the evidence presented concerning this item, the Commission finds that it is appropriate to apply the respective intrastate allocation factor to rate case expense as recommended by the Public Staff. Failure to apply the intrastate allocation factor would result in the over-recovery of rate case expense through intrastate rates and interstate operations.

<u>Miscellaneous Expenses</u>

Public Staff witness Szczech recommended in prefiled testimony the removal of certain miscellaneous expenses that she stated were not necessary in providing utility service. Her adjustment, in this regard, was the removal of $1,770 of nonutility expenses. The Company agreed with the Public Staff's adjustment in its proposed order.

Based on the foregoing, the Commission finds that it is appropriate to remove $1,770 for expenses that are not necessary for providing utility service.

<u>Gross Receipts Tax</u>

Public Staff witness Szczech recommended an increase of $404 for gross receipts tax based on the statutory rate of 3.22%. The difference between the Company and the Public Staff is based solely on the different recommended levels of local service revenues relating to touchtone and custom calling service offerings.

As discussed in the Evidence and Conclusions for Finding of Fact Nos. 24 and 25, the Commission found the revenue levels for touchtone and custom calling service offerings as proposed by the Company to be appropriate. Therefore, the Commission concludes that the appropriate level of gross receipts tax is $160 as recommended by the Company.

Other Taxes

Public Staff witness Szczech recommended a decrease of $222 for the regulatory fee based on the current statutory rate of .085%. According to witness Szczech, the regulatory fee expense included in the Company's application was the actual amount paid during the test year which reflected that the Company had applied the regulatory fee to all classes of revenue, both regulated and nonregulated, rather than just North Carolina jurisdictional revenues. Further, witness Szczech testified that she did not adjust the regulatory fee expense to reflect the Public Staff's adjustments to end-of-period revenues due to its immateriality. In its proposed order, the Company agreed with the Public Staff's adjustment.

Based on the foregoing, the Commission finds that it is appropriate to decrease other taxes by $222.

State and Federal Income Taxes

Public Staff witness Szczech applied the statutory state and federal income tax rates of 7.75% and 34%, respectively, to the Public Staff's recommended adjustments to operating revenues and expenses. The Company and the Public Staff are not in agreement on the level of state and federal income taxes due solely to the differences between the parties' recommendations on the appropriate levels of revenues and expenses.

Based on the Commission's findings in this Order, the appropriate levels of state and federal income taxes under present rates are ($2,781) and ($11,253), respectively.

Based on the foregoing, the Commission finds that the appropriate level of test year operating revenue deductions is $421,204 as shown in the following schedule:

Item	Amount
Plant specific operations	$ 78,436
Depreciation and amortization	135,932
Plant nonspecific operations	26,051
Customer operations	79,840
Corporate operations	108,914
Nonincome taxes/other oper. exp.	6,127
Total O&M Expenses	435,300
Gross receipts tax	160
Other taxes	(222)
State income tax	(2,781)
Federal income tax	(11,253)
Total operating revenue deductions	$421,204

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61 AND 62

The evidence concerning these findings of fact is found in the Stipulation of the Company and the Public Staff entered into on December 15, 1992. No other party offered any evidence as to the appropriate capital structure and cost rates. The Stipulation reflects the following capital structure and cost rates:

Item	Percent	Embedded Cost
Long-term Debt	79.75%	5.00%
Common Equity	20.25%	12.25%

Based on the foregoing, the Commission finds that the capital structure and cost rates stipulated to by the Company and the Public Staff are reasonable and appropriate for use in this proceeding. This combination of capital structure and cost rates yields an overall rate of return of 6.47%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 63

The evidence in support of this finding of fact is found in the testimony and exhibits of Company witness Meade and Public Staff witnesses Szczech, Garrison, Willis, Sutton, and Goetz and the Stipulation of the Company and the Public Staff.

Based upon the rate base, operating revenues, expenses, and rates of return as previously determined and set forth in this Order, the Commission finds that the Company should be allowed an increase in its gross operating service revenues of $120,491. This increase will allow the Company the opportunity to earn the 12.25% return on equity which the Commission has found reasonable.

The following schedules summarize the gross operating revenues and rate of return the Company should have a reasonable opportunity to achieve based upon the increase approved herein. Such schedules, illustrating the Company's gross revenue requirements, incorporate the findings and conclusions heretofore and hereinafter found reasonable by the Commission.

SCHEDULE I
SALUDA MOUNTAIN TELEPHONE COMPANY
DOCKET NO. P-76, SUB 33
STATEMENT OF NET OPERATING INCOME
North Carolina Intrastate Operations
Twelve Months Ended September 30, 1992

Item	Present Rates	Approved Increase	Approved Rates
Operating revenues:			
Local service	$123,122	$118,334	$241,456
Network access	64,974		64,974
Universal Service Fund	147,340		147,340
Long distance	116,316		116,316
Miscellaneous	37,811	2,157	39,968
Uncollectibles	(2,969)	(1,976)	(4,945)
Total operating revenues	486,594	118,515	605,109
Operating revenue deductions:			
Plant specific operations	78,436		78,436
Depreciation and amortization	135,932		135,932
Plant nonspecific operations	26,051		26,051
Customer operations	79,840		79,840
Corporate operations	108,914		108,914
Nonincome taxes/other operating	6,127		6,127
Gross receipts tax	160	3,746	3,906
Other taxes	(222)	98	(124)
State income tax	(2,781)	8,885	6,104
Federal income tax	(11,253)	35,964	24,711
Total operating revenue deductions	421,204	48,693	469,897
Net operating income for return	$ 65,390	$69,822	$135,212

SCHEDULE II
SALUDA MOUNTAIN TELEPHONE COMPANY
DOCKET NO. P-76, SUB 33
STATEMENT OF RATE BASE AND RATE OF RETURN
North Carolina Intrastate Operations
Twelve Months Ended September 30, 1992

Item	Amount
Telephone plant in service	$2,273,748
Accumulated depreciation	(189,040)
Net telephone plant	2,084,708
Working capital:	
Cash	24,947
Materials and supplies	14,842
Average tax accruals	(4,770)
Total working capital	35,019
Accumulated deferred income taxes	(16,179)
Postretirement benefits	(2,880)
Unamortized CPE gain	(10,225)
Original cost rate base	$2,090,443
Rates of return:	
Present rates	3.13%
Proposed rates	6.47%

SCHEDULE III
SALUDA MOUNTAIN TELEPHONE COMPANY
DOCKET NO. P-76, SUB 33
STATEMENT OF CAPITALIZATION AND RELATED COSTS
North Carolina Intrastate Operations
Twelve Months Ended September 30, 1992

Item	Capital-ization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		Present Rates		
Long-term debt	79.75%	$1,667,128	5.00%	$83,356
Common equity	20.25%	423,315	(4.24)%	(17,966)
Total	100.00%	$2,090,443		$65,390
		Approved Rates		
Long-term debt	79.75%	$1,667,128	5.00%	$83,356
Common equity	20.25%	423,315	12.25%	51,856
Total	100.00%	$2,090,443		$135,212

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 64

The evidence for this finding of fact is found in the testimony and exhibits of Public Staff witnesses Szczech and Garrison as well as the Evidence and Conclusions for Findings of Fact Nos. 23 and 60.

Mr. Garrison testified that the separations factors used by Saluda Mountain in this case were reasonable and that the Public Staff's end-of-period adjustments reflect the separations factors used by Saluda. Mr. Garrison's Exhibit No. JTG-1 shows the Public Staff's calculation of the end-of-period intrastate interLATA billing and collection revenue requirement to be $16,487. Based upon the evidence, the Commission recognizes that the Public Staff's intrastate interLATA billing and collection revenue requirement reflects the end-of-period investment and expenses which it recommended. Therefore, the Commission believes it would be proper to accept the Public Staff's intrastate interLATA billing and collection level as the starting point for determining the revenue requirement to include in this proceeding. Using the data filed by the Public Staff on September 8, 1993, in response to the September 2, 1993 data request issued by the Commission and recognizing the conclusions which the Commission has made and discussed elsewhere herein, the Commission concludes that the proper level of intrastate interLATA billing and collection revenue to be included in this proceeding is $16,725.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 65

The evidence for this finding of fact is contained in the testimony and exhibits of Public Staff witness Garrison, and in the Evidence and Conclusions of Findings of Fact Nos. 30 and 64.

The only direct testimony regarding revisions to the interLATA billing and collection rates was offered by Mr. Garrison. He testified that the revenue requirement for interLATA billing and collection services was higher than the revenues received for those services. Therefore, he concluded that it was appropriate for the interLATA billing and collection rates to be increased to cover the shortfall. The Commission concludes that the billing and collection rates for Saluda Mountain should be increased by 14.8% to recover the $2,157 shortfall in the interLATA billing and collection revenue requirement determined by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence for this finding of fact is contained in the testimony and exhibits of Company witness Meade, Public Staff witness Garrison, AT&T witness King, King Cross-Examination Exhibit Nos. 1 and 2, and the following Commission Orders: the Commission's Orders of April 8, 1988, (Bill and Keep Order) and August 28, 1991, in Docket No. P-100, Subs 65 and 72, and the Commission's Order of October 20, 1992, in Docket No. P-21, Sub 54, (Ellerbe Telephone Company) of which the Commission takes judicial notice.

Both Mr. Meade and Mr. Garrison testified that the interLATA access revenues should cover the jurisdiction's costs and that rates were designed to produce that result. Based upon a separations study, Company witness Meade testified that interLATA access should be increased by raising the originating carrier common line charge (OCCL) to the maximum $0.0583 approved by the Commission in 1988 when intrastate interLATA access was depooled. He further proposed that the remainder of the access increase be recovered through the high cost fund, which was also established at the time of depooling. Public Staff witness Garrison agreed that access revenues should be increased, on the basis of the separation factors used by the Company, by raising the OCCL for Saluda Mountain and adding the Company to the high cost fund. Mr. Garrison on cross-examination calculated that this proposal would amount to a 61% increase in access revenues for the Company.

AT&T witness King recommended that access rates be reduced so that the intrastate interLATA access rates match Saluda Mountain's interstate access rates. He stated that "access rates need to be going down, not up."

Mr. King testified that the proposed increase would result in access rates that exceed the average revenue per minute that AT&T is able to recover in rates under the system of statewide averaged long distance rates. Mr. King also testified that interLATA access charges in North Carolina are among the highest in the country and are substantially higher than in the interstate jurisdiction.

Mr. Meade testified that the interstate access rates charged by Saluda Mountain do not reflect the costs that the Company incurs in providing interstate access service.

The Commission can find no sound reason to decrease Saluda's intrastate interLATA access rates to match its interstate access rates. While we recognize that all subscribers, including interexchange carriers, will benefit from Saluda Mountain's improved facilities, the Commission nevertheless concludes that the proposal of the Public Staff and the Company to recover a portion of the revenue requirement from increasing the OCCL element and adding the Company to the high cost fund should be rejected. First, since Saluda's last general rate case was 35 years ago, the increase in local rates is not unreasonable especially in view of the Company's current low residential rate of only $5.39 per month. Second, while the Bill and Keep Order of April 8, 1988, did not specifically prohibit a company's OCCL rate from being increased, that Order did contain language clearly indicating the expectation that company-specific OCCL rates would eventually decrease to zero. In the last telephone rate case before this Commission, that of Ellerbe Telephone Company, Docket No. P-21, Sub 54, the Commission did not approve an increase in access rates. The Commission is not prepared to do so in this case. We are not willing to depart from the procedures established in the industry plan applicable to all LECs for the depooling of interLATA access charges. Pending review of the depooling plan as a whole, we are reluctant to change that plan in any way.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67 and 68

The evidence supporting these findings of fact is found in the Company's application and the testimony and exhibits of Company witness Meade and Public Staff witness Willis.

The Company proposed to eliminate zone charges and to obsolete all multi-party service. Mr. Meade testified that the Company proposed to increase nonrecurring rates and charges to the levels charged by similarly situated companies.

Public Staff witness Willis testified that the Company had proposed to increase its rates for all basic exchange services and service connection charges and to eliminate zone charges. Mr. Willis testified that he was in agreement with all the Company's proposals except for the level of basic exchange rates.

He indicated that his proposed exchange rates differed because of the Public Staff's proposed revenue requirement and the effect of other proposed changes in rate design.

Mr. Willis testified that his recommendations would produce the $62,287 of additional local service revenue recommended by the Public Staff. Mr. Willis presented exhibits showing the present rates, the Public Staff proposed rates, and calculations of the revenue increase that would be produced by the Public Staff's proposals. He stated that both he and the Company used multiples in proposing the basic exchange rates that are typical of those currently used in North Carolina by other telephone companies. Mr. Willis indicated that the proposed rate for rotary line service is 50% of the business one-party line rate. He further indicated that he was in agreement with the service connection charges proposed by the Company and that the proposed charges are the same as Southern Bell Telephone and Telegraph Company's existing charges. Mr. Willis indicated that the proposed Directory Listings, Local Coin Telephone, and Directory Assistance charges are the same as those found reasonable by the Commission in the last Ellerbe Telephone rate case proceeding. He also testified that the Maintenance of Service and Return Check charges are based upon an agreement of the Public Staff and Company to increase each by $5.00.

The Commission has carefully considered all of the evidence. The Company and the Public Staff are in agreement regarding the elimination of zone charges as well as the level of all proposed rates and charges other than basic exchange rates. The Commission notes that even in regard to the basic rates, both the Company and the Public Staff used the same multiples in proposing the residence and business rates. The Commission concludes that the rates and charges set out in Appendix B are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant, Saluda Mountain Telephone Company, be, and hereby is, authorized to increase its local service rates and charges and its intrastate billing and collection rates so as to produce an increase of $120,491 above the level of revenue that would have resulted from rates currently in effect, based on the test year level of operations.

2. That the Applicant is required to file modified tariff sheets prepared pursuant to this Order and to the guidelines contained in Appendix B within 10 days from the date of this Order.

3. That the Applicant is required to coordinate with Southern Bell, the Industry Access Tariff Administrator, and cause to be filed within 10 days from the date of this Order tariffs reflecting an across-the-board increase of 14.8% for Saluda Mountain's billing and collection rates.

4. That the Public Staff may file written comments concerning the Company's tariffs within five working days of the date on which they are filed pursuant to Ordering Paragraphs 2 and 3 above.

5. That the Applicant shall give notice of the rate increase approved herein to each of its North Carolina customers following the filing and acceptance of the tariff sheets described in Ordering Paragraph No. 2 above. The Company shall submit its proposed customer notice to the Commission for approval prior to the notices being mailed out to the customers.

6. That the rates, charges, and regulations necessary to produce the annual gross revenues authorized herein shall become effective upon the issuance of a further Order approving the tariffs and customer notices filed pursuant to the ordering paragraphs above.

7. That the Chief Clerk shall mail a copy of this Order to Southern Bell.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

SALUDA MOUNTAIN DEPRECIATION RATES

ACCOUNT (A)	ACCOUNT DESCRIPTION (B)	APPROVED RATES (%) (C)
2112000	Motor Vehicles	11.6
2116000	Other Work Eqpt.	8.8
2121000	Building	2.5
2122000	Furniture	8.8
2123100	Office Support Eqpt.	7.9
2123200	Company Communications Eqpt.	7.9
2124000	General Purpose Computers	14.3
2212000	Digital COE	5.6
2232000	Circuit Eqpt.	8.5
2232400	Circuit Eqpt.—Concentrators	8.5
2232500	Circuit Eqpt.—Fiber Optic	7.8
2321000	Customer Premises Wire	n/a
2351000	Public Telephone Eqpt.	10.5
2411000	Pole Lines	5.2
2421100	Aerial Cable	5.8
2421200	Aerial Cable—Non Metallic	4.4
2422100	Underground Cable—Metallic	5.8
2423100	Buried Cable—Metallic	5.3
2431000	Aerial Wire	10.8
2681000	Capital Leases	2.5
2682000	Leasehold Improvements	2.5

APPENDIX B
DOCKET NO. P-76, SUB 33
PAGE 1 OF 3

SALUDA MOUNTAIN TELEPHONE COMPANY
LOCAL SERVICE REVENUES
SUMMARY

	TEST YEAR REVENUE		
CATEGORY OF SERVICE	PRESENT	APPROVED	INCREASE
BASIC LOCAL EXCHANGE SERVICE	$83,373.52	$211,426.29	$128,052.77
ZONE CHARGES	$21,923.04	$0.00	($21,923.04)
SERVICE CHARGES	$2,970.04	$9,061.00	$6,090.96
OTHER RATES AND CHARGES			
DIRECTORY ASSISTANCE	507.20	1,115.75	608.55
RETURN CHECK CHARGE	50.00	75.00	25.00
MAINTENANCE OF SERVICE	560.00	700.00	140.00
DIRECTORY LISTINGS-RESIDENTIAL	17.28	68.40	51.12
DIRECTORY LISTINGS-BUSINESS	25.92	124.20	98.28
DIRECTORY LISTINGS-NONLISTED NUMBER	123.48	214.20	90.72
DIRECTORY LISTINGS-NONPUBLISHED NUMBER	629.16	2,182.80	1,553.64
COIN TOTAL	2,364.00	5,910.00	3,546.00
TOTAL OTHER CHARGES	$4,277.04	$10,390.35	$6,113.31
TOTAL LOCAL SERVICE REVENUE			$118,334.00

APPENDIX B
DOCKET NO. P-76, SUB 33
PAGE 2 OF 3

SALUDA MOUNTAIN TELEPHONE COMPANY
BASIC LOCAL EXCHANGE SERVICE

CLASS OF SERVICE	MONTHLY RATES PRESENT	APPROVED
BUSINESS SERVICES		
BUSINESS ONE PARTY	$8.21	$28.78
BUSINESS TWO PARTY	6.75	28.78
BUSINESS PBX TRUNK	N/A	52.36
BUSINESS ROTARY LINE SERVICE		14.39
RESIDENCE SERVICE		
RESIDENCE ONE PARTY	$5.39	$11.51
TWO PARTY	4.42	11.51
FOUR PARTY	3.69	11.51

All zone charges are eliminated.

APPENDIX B
DOCKET NO. P-76, SUB 33
PAGE 3 OF 3

SALUDA MOUNTAIN TELEPHONE COMPANY
SERVICE CHARGES

	PRESENT RATE	APPROVED RATE
INSTALLATION CHARGES		
SERV.CONN.–PREMISE VISIT – RES.	$ 4.86	$10.25
– BUSINESS	4.86	10.25
SERV.CONN.–CENTAL OFFICE – RES.	2.91	15.25
– BUSINESS	3.40	21.25
PRIMARY ORDER CHARGE – RES.	10.68	27.50
– BUSINESS	16.51	41.25
SECONDARY ORDER CHARGE – RES.	6.31	10.75
– BUSINESS	8.20	14.50
RECORD ORDER CHARGE – RES.	2.43	10.75
– BUSINESS	2.91	14.50

OTHER RATES AND CHARGES

	PRESENT RATE	APPROVED RATE
DIRECTORY LISTING–RESIDENTIAL	0.24	0.95
DIRECTORY LISTING–BUSINESS	0.24	1.15
DIRECTORY LISTING–NONLISTED NUMBER	0.49	0.85
DIRECTORY LISTING–NONPUBLISHED NUMBER	0.49	1.70
RETURN CHECK CHARGE	10.00	15.00
MAINTENANCE OF SERVICE	20.00	25.00
DIRECTORY ASSISTANCE		
5 FREE CALLS/MO; $.20/CALL THEREAFTER	0.20	
3 FREE CALLS/MO; $.25/CALL THEREAFTER		0.25
LOCAL COIN TELEPHONE SERVICE	0.10	0.25

DOCKET NO. P-76, SUB 33

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Saluda Mountain Telephone) Company for Authority to Adjust its Rates) and Charges for Intrastate Telephone Service)	ERRATA ORDER AND ORDER APPROVING TARIFF FILING AND CUSTOMER NOTICE

BY THE COMMISSION: On September 17, 1993, the Commission issued its Order Granting Partial Rate Increase in the above-captioned matter. Ordering Paragraphs 2 and 3 of said Order required that the Company file with the Commission modified tariff sheets designed to produce the increase in revenues adopted in said Order. Ordering Paragraph 5 of said Order required that the Company file with the Commission its proposed public notice.

On September 27, 1993, Southern Bell filed tariff sheets reflecting the changes in Saluda's billing and collection rates and on September 29, 1993, the Company filed its modified tariff sheets; both filings were made in accordance with the requirements contained in the Commission Order of September 17, 1993. On October 1, 1993, the Public Staff filed a letter stating that it had reviewed the proposed tariffs and agreed that they complied with the guidelines of the Commission's Order and that they had no objection with the tariffs becoming effective on November 7, 1993, as requested by the Company.

The tariffs as filed on September 29, 1993, correctly reflect a monthly rate of $50.36 for a business PBX trunk, rather than the rate of $52.36 which was inadvertently shown in Appendix B, page 2 of 3 of the Commission's Order. The Commission finds good cause to order the correction of this error. Further, the Commission is of the opinion that the rates and service regulations reflected in both Southern Bell's and the Company's tariff filings appear to correctly implement the intent of the Commission Order of September 17, 1993, and that they should be approved.

On October 7, 1993, the Company filed a proposed public notice in accordance with the requirements contained in the Commission Order of September 17, 1993. The Company filed a revised proposed customer notice on October 8, 1993. The Commission is of the opinion that the public notice should be approved as modified herein.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's tariffs filed herein on September 27 and 29, 1993, are hereby approved.

2. That the page labeled Appendix B, Page 2 of 3, attached hereto as Attachment I, shall be substituted for Appendix B, Page 2 of 3, attached to the Commission Order issued on September 17, 1993, in the above-captioned matter.

3. That the public notice, attached hereto as Attachment II, is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Attachment I

APPENDIX B
DOCKET NO. P-76, SUB 33
PAGE 2 OF 3

SALUDA MOUNTAIN TELEPHONE COMPANY
BASIC LOCAL EXCHANGE SERVICE

CLASS OF SERVICE	MONTHLY RATES PRESENT	MONTHLY RATES APPROVED
BUSINESS SERVICES		
BUSINESS ONE PARTY	$8.21	$28.78
BUSINESS TWO PARTY	6.75	28.78
BUSINESS PBX TRUNK	N/A	50.36
BUSINESS ROTARY LINE SERVICE		14.39
RESIDENCE SERVICE		
RESIDENCE ONE PARTY	$5.39	$11.51
TWO PARTY	4.42	11.51
FOUR PARTY	3.69	11.51

All zone charges are eliminated.

Attachment II
(Page 1 of 2)

Dear Customer:

After months of investigation and public hearings, the North Carolina Utilities Commission entered an Order on September 17, 1993, allowing Saluda Mountain Telephone Company an annual increase in its rates and charges of $120,000. The rate increase will be effective on and after November 7, 1993.

The Company's application for rate relief was filed with the Commission on February 16, 1993. The Company initially requested an increase of $159,000, but revised its request to $171,000 at the public hearings.

The principal reasons underlying the increase in rates were increases in costs since the Company's last general rate case in October 1957, 35 years ago. These increased costs are primarily the result of more than $2.5 million in new investments. During the past few years, the Company installed approximately 160 route miles of aerial and buried cable facilities, fiber optics and a Northern Telecom DMS-10 digital central office switch.

This new construction has allowed the upgrading of all customers to single party service. It also provides customers with the option of subscribing to Touchtone Calling and Custom Calling Features, such as: Call Waiting, Speed Calling, Call Forwarding and many more.

The new rates, approved by the North Carolina Utilities Commission, are listed on the back of this notice and are effective with this month's bill. In addition to the new rates, the Commission ordered the elimination of zone mileage charges.

If you have any questions or desire more information, please feel free to call or stop by our business office on Main Street.

TDS TELECOM
Saluda Mountain Telephone Company
749-3601

SALUDA MOUNTAIN TELEPHONE COMPANY
APPROVED RATES

Basic Service	Residence	Business
One-Party	$11.51	$28.78
Two-Party (Eliminated)	-	-
Four-Party (Eliminated)	-	-
Zone-Mileage (Eliminated)	-	-
PBX Trunk	N/A	$50.36
Rotary Line Service	N/A	$14.39
Installation Charges		
Premise Visit	$10.25	$10.25
Central Office Connection	$15.25	$21.25
Primary Service Order Charge	$27.50	$41.25
Secondary Service Order Charge	$10.75	$14.50
Record Order Charge	$10.75	$14.50
Other Rates and Charges		
Additional Directory Listing	$ .95	$ 1.15
Non-Listed Number	$ .85	$ .85
Non-Published Number	$ 1.70	$ 1.70
Return Check Charge	$15.00	$15.00
Maintenance of Service	$25.00	$25.00
Directory Assistance		
3 free calls/month: ea. addl. call	.25	.25
Local Coin Telephone Svc. per call	.25	.25

DOCKET NO. P-246, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Provision of Intrastate Telecommunication Services by Metromedia Communications Corporation Using Rates in Excess of Those Contained in Approved Tariff	ORDER APPROVING SETTLEMENT

BY THE COMMISSION: On February 9, 1993, Metromedia Communications Corporation (Metromedia) petitioned the Commission for an Order approving the settlement set forth below between itself and the Public Staff. In support of its petition, Metromedia stated that it and the Public Staff have agreed:

1. The Public Staff filed a Motion for Order to Show Cause, to Cease and Desist, and to Refund Monies in Excess of Tariffed Rates on April 13, 1992, alleging in pertinent part that Metromedia was providing intrastate telecommunications services in North Carolina in excess of tariffed rates approved by the Commission.

2. In response to the motion, Metromedia provided the Public Staff with documentation regarding its telecommunications services in North Carolina.

3. After reviewing Metromedia's submissions, the Public Staff determined that Metromedia had overcharged callers in the amount of $14,369.90.

4. After reviewing the specific allegations of the Public Staff set forth in the motion and subject to approval of the Commission, Metromedia agrees:

a. To credit all telephone traffic that was charged in excess of tariffed rates plus applicable interest fat the rate of 10% as provided by G.S. 62-131 if such traffic can be credited in the same manner by which it is billed (i.e., through an automated credit system of a local exchange carrier).

b. To pay as a lump sum to the State of North Carolina the remainder of the amount that was overcharged plus the applicable interest.

5. Metromedia's actions taken pursuant to paragraph 4 above shall constitute and result in the final and complete settlement of this matter. Once the amount in question is credited or paid to the State of North Carolina, the Public Staff will withdraw its motion and will agree nor to file the same or a substantially similar motion regarding the specific incidents set forth in the motion.

6. Both Metromedia and the Public Staff are of the opinion that this settlement will provide equitable treatment to all callers whose telephone traffic is the subject of the motion and believes that the settlement is thus in the best interests of those callers and the State of North Carolina. Metromedia and the Public Staff, therefore, recommend approval of this settlement, as enunciated and outlined above.

After careful consideration of the filings in this docket, the Commission is of the opinion that the settlement should be approved and that refunds should be made to affected customers pursuant to paragraphs 4a and b above.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. P-55, SUB 936

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Southern Bell Telephone and Telegraph Company Tariff Filings to Implement a Coastal Regional Calling Plan	)))	ORDER DENYING EXPANSION OF PLAN

BY THE COMMISSION: On December 7, 1992, Southern Bell Telephone and Telegraph Company (Southern Bell) filed tariffs with an effective date of February 6, 1993, proposing to change the name of the Pender County Calling Plan (PCCP) to the Coastal Regional Calling Plan (CRCP) and to include the Carolina Beach and Wrightsville Beach exchanges in the CRCP.

The PCCP was implemented on an experimental basis on July 19, 1991, and is scheduled to last for 18 months (until January 18, 1993). The PCCP provided expanded local calling between the following Southern Bell exchanges: Atkinson, Burgaw, Castle Hayne, Scotts Hill, and Wilmington. While the PCCP was developed in response to requests primarily from Pender County and thus named for the County, Southern Bell indicated that the name has been a source of confusion since a majority of the subscribers to the plan live in Wilmington and not in Pender County. Therefore, Southern Bell proposed to clear the confusion by changing the name of the plan to the Coastal Regional Calling Plan which better describes the area served by the plan.

Since the PCCP was implemented, Southern Bell stated that it had received numerous requests from subscribers in the Carolina Beach and Wrightsville Beach exchanges to be included in the plan. Also, resolutions have been adopted by the Board of Aldermen of the Town of Wrightsville Beach, the Carolina Beach Town Council, and the Kure Beach Town Council to be included in the plan. This tariff filing proposes to add these two exchanges to the plan on both an originating and terminating basis.

This matter came before the Regular Commission Conference on December 14, 1992. The Public Staff recommended that the Commission allow Southern Bell's proposed tariff to become effective on February 6, 1993, as filed.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration of the filings in this docket, the Commission is of the opinion that Southern Bell should be allowed to change the name of the Pender County Calling Plan to the Coastal Regional Calling Plan but that the CRCP should not be expanded at this time to include new exchanges. While the Commission certainly understands why subscribers in certain exchanges--and the telephone company serving those exchanges--might wish to participate in a plan providing for discount calling, the Commission believes that it would be unwise to expand an experimental plan before the experimental time period has expired and a decision has been reached as to whether to make these plans permanent. This is particularly true here where expansion is asked toward the end of the experimental period but before the final report has been submitted. The Commission has added exchanges to experimental plans in the past--notably

Kernersville in the Triad Regional Calling Plan--but this was done before the Triad Regional Calling Plan had gotten underway and in lieu of granting extended area service.

The Commission, furthermore, believes that proposals to expand experimental plans should be placed in the larger perspective. For example, there have been indications that the local exchanges companies may wish to propose a statewide discount plan, and other actions that the Commission may take may affect the relative desirability and merits of discount plans such as this one. The Commission does not believe that it should take any action which would tend to prejudge the merits of the experimental plans currently underway and give subscribers and telephone companies the impression that these plans are necessarily permanent, at least in their present form. To expand the CRCP at this time would tend to foster this impression.

However, in order to clarify the intent of its original Order in this docket, the Commission does not believe that the CRCP should expire as a provisional service offering at the end of the 18-month period scheduled for January 19, 1993. Rather, it has been the Commission's intent that while the experiment is to expire on that date, the service offerings should provisionally continue in effect pending further Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the name of the Pender County Calling Plan be changed to the Coastal Regional Calling Plan.

2. That the caption of this docket be changed to read "Southern Bell Telephone and Telegraph Company Tariff Filings to Implement a Coastal Regional Calling Plan."

3. That the tariff filing by Southern Bell to include the Carolina Beach and Wrightsville Beach exchanges in the Coastal Regional Calling Plan be denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of January 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. P-55, SUB 942

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Tariff Filing by North State Telephone Company and Southern Bell Telephone and Telegraph Company for Implementing the Triad Regional Calling Plan) ORDER DENYING EXPANSION OF PLAN

BY THE COMMISSION: On December 1, 1992, ALLTEL Carolina (ALLTEL) filed preliminary tariffs to include its exchanges of King, Lewisville, Old Town, Rural Hall, and Stanleyville in the Triad Regional Calling Plan (TRCP). Early approval of the proposed expansion was requested in order to begin preparations to implement the expansion during the first quarter of 1993. ALLTEL proposed to offer the TRCP in response to requests from, and subsequent meetings with, Triad chambers of commerce, citizen groups, and government officials. These five exchanges were included in the studies conducted in the earlier Triad Regional extended area service (EAS) proposal in Docket No. P-55, Sub 898.

The Plan expansion proposed by ALLTEL, which is similar to Central Telephone Company's (Central's) plan offered at its Walkertown exchange, will offer subscribers seven-digit dialing to other Triad area exchanges at a 50% discount from regular toll rates. The proposal does not include a Thrifty Calling Option or an Inward Call Billing Service Option. The expansion is proposed on an experimental basis to run concurrently with the experimental period for the other plans being offered by Carolina Telephone and Telegraph Company (Carolina), Central, North State Telephone Company (North State), and Southern Bell Telephone and Telegraph Company (Southern Bell) in the Triad region. In order for ALLTEL's exchanges to be included fully in the TRCP, the other participating local exchange companies (LECs) will need to expand their plans to include the ALLTEL exchanges as terminating points.

This matter came before the Regular Commission Conference on December 14, 1992. The Public Staff recommended that the Commission grant early approval of ALLTEL's proposed expansion of the TRCP to be implemented in coordination with the expansion of the plans offered by the other LECs in the Triad by including the ALLTEL exchanges as terminating points.

Raymond Brooks, Regulatory Manager for ALLTEL, appeared in support of the Company's proposed tariff filing and stated that ALLTEL hopes to have its plan in effect by March 31, 1993.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

While the Commission certainly understands why subscribers in certain exchanges--and telephone companies serving those exchanges--might wish to participate in a plan providing for discount calling, the Commission believes that it would be unwise at this time to expand experimental plans before the experimental time period has expired and a decision has been reached on whether to make these plans permanent. The Commission has, of course, added exchanges to experimental plans in the past--notably Kernersville in the TRCP--but this was done before the TRCP had gotten underway and in lieu of granting EAS.

The Commission believes that these proposals should be placed in a larger perspective. The LECs have indicated that they may wish to propose a statewide discount plan and actions that the Commission may take in the future may affect the relative desirability and merits of discount plans such as the TRCP. The Commission does not believe that it should take any action that would tend to prejudge the merits of the experimental plans currently underway and give subscribers and the telephone companies the impression that these plans are necessarily permanent, at least in their present forms. The Commission believes that expanding the TRCP at this time would tend to foster this impression.

IT IS, THEREFORE, ORDERED that ALLTEL's proposal relating to the expansion of the TRCP to the exchanges of King, Lewisville, Old Town, Rural Hall, and Stanleyville be denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of January 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. P-140, SUB 34

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Tariff Filing by AT&T Communications of the Southern States, Inc., to Eliminate the Day-Save Rate Period for its Message Telecommunications Service	) ORDER REQUIRING NOTICE

BY THE COMMISSION: On October 19, 1992, AT&T Communications of the Southern States, Inc. (AT&T), made tariff filings in the above docket. Pursuant to Commission rules regarding notice of rate increases to customers, AT&T caused a bill insert to go out to its customers concerning the proposed rate increase. However, in that notice, AT&T failed to indicate that the rate increase was contingent upon favorable Commission action. On December 11, 1992, the Commission issued an Order Dismissing Tariff Filing to Eliminate Day Save Rate.

The Commission believes that it is very probable that AT&T customers exist who have the erroneous impression that there has been a change of rates pursuant to the above tariff filing when such is not the case. The Commission, therefore, believes that AT&T should be required to send out a notice by bill insert to its customers to inform them that there is no change in rates. However, it is not necessary that AT&T detail the rate schedules in the manner of the previous notice.

IT IS, THEREFORE, ORDERED as follows:

1. That no later than Tuesday, January 26, 1993, AT&T submit to the Commission a proposed notice consistent with this Order for the Commission's review and approval.

2. That AT&T send the approved notice to its customers by bill insert as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of January 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Commissioners Julius A. Wright, Robert O. Wells, and Laurence A Cobb dissent.

DOCKET NO. P-140, SUB 34

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Tariff Filing by AT&T Communications of the Southern States, Inc., to Eliminate the Day Save Rate Period for Its Message Telecommunications Service	ORDER RECONSIDERING NOTICE REQUIREMENT

BY THE COMMISSION: On January 12, 1993, the Commission issued an Order Requiring Notice. A proposed notice was to be submitted by January 26, 1993, with issuance thereafter "as soon as practicable." On January 22, 1993, AT&T Communications of the Southern States, Inc. (AT&T), filed a Petition for Reconsideration and Motion to Defer Compliance Date. In the latter matter, the Chairman deferred the compliance date to January 29, 1993.

In its petition for reconsideration, AT&T argued that its previous notice had been submitted months previously to the Public Staff, that the Public Staff had urged changes including the use of a bill insert, and that the Public Staff had approved the notice. The Commission did not object to the notice in a timely fashion, and the notice should be "deemed approved by the Commission as submitted and the regulated company must be able to rely on that approval." AT&T further argued that it did not believe that AT&T customers are misinformed concerning the rates. Neither complaints nor inquiries have been received.

Lastly, AT&T argued that it would incur a substantial expense--$65,000 for a bill message--in order to re-notice customers. When added to the $180,000 for the original notice, this would mean that AT&T would have spent $245,000 for a filing not allowed to go into effect.

The Public Staff took no position on AT&T's motion for reconsideration.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration of the filings in this docket, the Commission believes that it should reconsider its January 12, 1993, Order Requiring Notice and release AT&T from the requirement of having to furnish further notice to its customers regarding the continuation of the Day Save Rate Plan.

The Commission believes that AT&T has made several points that should be given weight. For example, AT&T has added perspective on the way in which the original notice requirement process was handled and has presented figures regarding the additional cost of a second notice requirement. AT&T has also pointed out that few customers seem to be actually confused or misinformed about the status of the Day Save rate in view of the fact that neither complaints nor inquiries have been received.

Accordingly, while the Commission continues to strongly support the public interest in consumer notification and believes that the Day Save rate should continue, the Commission does not believe that the public interest will be impaired if AT&T is relieved of the additional notice requirement in this instance. However, in the interest of public notification, the Commission intends to issue a press release concerning the continuance of the Day Save rate period.

IT IS, THEREFORE, ORDERED that the Commission's January 12, 1993, Order Requiring Notice be rescinded and that AT&T not be required to make any further public notice regarding the continuance of the Day Save rate period in this docket.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Commissioners Sarah Lindsay Tate and Allyson K. Duncan dissent.

DOCKET NO. P-343
DOCKET NO. P-100, SUB 114

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. P-343

In the Matter of Proposed Cellular Service of U.S. Osiris Corporation, d/b/a American Roaming Network DOCKET NO. P-100, SUB 114 In the Matter of Exemption of Domestic Cellular Radio Telecommunications Service Providers from Regulation Under Chapter 62 of the North Carolina General Statutes	ORDER RULING ON PETITION FOR DECLARATORY RULING

BY THE COMMISSION: On April 20, 1993, U.S. Osiris Corporation, d/b/a American Roaming Network (Osiris) filed a Petition for Declaratory Ruling that its proposed service, described below, is exempt from regulation. Osiris categorized itself as a reseller of cellular service proposing to offer a type of cellular service to permit roaming customers outside the home cellular geographic service areas (CGSAs) to complete cellular calls. Osiris's proposed service will offer roaming customers in GTE Mobile Communications, Inc.'s (GTE's) CGSA the opportunity to complete cellular calls.

Osiris intends to enter into an agreement with GTE whereby cellular customers roaming in a GTE CGSA will receive a recording offering them the opportunity to complete their calls over Osiris's network. Osiris proposes to pick up the calls from a GTE super node in North Carolina and transport them via inter-machine trunks to the Osiris switch in Texas. The callers would then hear a recording welcoming them to Osiris Network, and requesting them either to enter a valid calling card number or request live operator assistance. If the caller requests operator assistance, the operator would advise the caller of available billing options such as making a collect call, billing to a third-party number, or using a commercial credit card. Osiris would bill the call via the customer's requested billing mechanism. Osiris stated that the operator's role is only to make billing arrangements. Osiris is offering its service in GTE CGSAs in other jurisdictions. It is not offering its service in North Carolina GTE CGSAs. In the Raleigh MSA alone, Osiris said there have been approximately 400 attempts per day to use the service proposed by Osiris, and customers have complained that they are unable to complete their cellular calls. The calls are typically cellular-to-land but could be cellular-to-cellular. Applicable charges for the service would include a permanent network charge based on per-minute use, a $3.85 call set-up and operator service charge, and GTE's or other originating cellular carrier's air-time charges.

The Public Staff opposed Osiris's proposal, characterizing Osiris among other points, as an alternative operator service (AOS) provider, a type of entity not permitted in North Carolina on an intrastate basis.

The AOS Order to which the Public Staff referred was issued in Docket Nos. P-100, Sub 84 and P-100, Sub 101, on March 16, 1988, and found that intrastate certification of AOS is not in the public interest. Subsequently, G.S. 62-110.4 forbade the Commission to issue certificates to interexchange carriers (IXCs) "which the Commission has determined to have the characteristics of an alternative operator service" unless the Commission has determined them to be in the public interest and has enacted appropriate rules. In the AOS Order, the Commission defined an AOS provider as an IXC which "specializes in the business of offering operator services to transient venues." In its analysis of the AOS issue, the Commission emphasized the importance of protecting the end-user who "may be 'captive' as well as transient." In the typical AOS situation, the Commission said that the customer of the AOS is not the end-user but the aggregator, such as a hotel, motel, or payphone, who usually receives a commission from the AOS to allow the AOS access to its premises. The Commission noted that an "observed feature of AOS providers is that they tend to charge much higher than normal rates" because of their monopoly position within a given venue. In distinguishing between AOS and other IXCs, the Commission emphasized the non-identity between the AOS customer (the aggregator) and the end-user; the mutual interest by the aggregator and AOS in keeping rates high; and the inherent opportunities for overreaching in the transient venue, with limited end-user notice and choice. The Commission in its AOS Order also cited and relied on the historical record of abuses committed by the AOS industry as a whole.

On April 23, 1993, the Commission issued an Order Requesting Comments.

The following parties filed comments and reply comments: The Public Staff, MetroMobile CTS of Charlotte, Inc., d/b/a Bell Atlantic Mobile (BAM), Cellular Express, Inc. (CEI), Cellular One, and GTE Metronet (GTEM).

Initial Comments

Public Staff Comments. The thrust of the Public Staff comments was that Osiris could not be properly classified as a cellular carrier and that, in fact, its proper classification is as an AOS. The Public Staff noted that the Commission has indeed exempted cellular carriers and cellular resellers from regulation by Order issued February 14, 1992. However, the Public Staff denied that Osiris should be classified as either a cellular carrier or a cellular reseller. The Public Staff pointed out that Osiris owns no cellular facilities and does not propose to provide basic cellular service. Its sole purpose is to act as a means for cellular mobile users to complete long distance calls when roaming.

When it does this, Osiris passes through the cellular airtime charges which it has to pay to the local cellular carrier. The Public Staff argued that this pass-through was the only basis by which Osiris can claim to be entitled to regulatory exemption. The Public Staff denied that this is sufficient basis. The Public Staff characterized the pass-through as an access charge billing mechanism only, one which could be easily eliminated as a separate charge and incorporated in the long-distance per-minute charges that Osiris could make to customers. As an analogy, the Public Staff pointed to the recovery by interexchange carriers of local exchange company (LEC) access charges. The use of local access by an IXC to complete a long-distance call does not make an IXC an LEC. Similarly, the use by Osiris of cellular access (airtime) to complete a long-distance call from a cellular phone does not make Osiris a cellular carrier. The Public Staff contended that the proper classification of a carrier is dependent upon the type of service it provides rather than the rate elements it charges.

Since Osiris is not properly a cellular carrier, the Public Staff argued that its correct classification is that of an AOS. The general definition of an AOS is an IXC which specializes in offering operator services to transient venues. In the instant case, Osiris's customers would be transient users with no continuing contractual relationship to Osiris. The use of Osiris would be the cellular end-user's only choice if he wanted to make a cellular long-distance call in the foreign area. These circumstances, the Public Staff maintained, closely parallel the "captivity"--i.e., the lack of information and choice--facing the AOS end-user.

The Public Staff further argued that such lack of choice is reinforced by the fact that equal access is not required of cellular carriers and the recent Federal Communications Commission (FCC) action to require 10XXX unblocking by aggregators does not apply to the instant context.

Lastly, the Public Staff argued that the preferable solution for roamers is for the cellular companies to negotiate reciprocal agreements. Allowing Osiris to operate would remove the incentive to negotiate such agreements.

Bell Atlantic Mobile. BAM argued that if the Commission determines that Osiris is not operating as an AOS, the Commission should establish the following conditions with respect to Osiris's service:

1. Proposed services to be offered by Osiris should be limited to nonaffiliated roamers within the State of North Carolina.

2. The billing for the proposed services should be made directly to the cellular user and not to the home cellular carrier. When the user receives its bill for charges, the invoice should state that the charges are from Osiris and should provide a phone number to enable the user to identify the call as having been made through the services provided by Osiris.

3. The cellular user should be informed of the options with respect to the proposed service being offered by Osiris and the cellular user should be allowed to elect not to use the service without incurring a charge.

4. Osiris should be subject to the Commission's February 14, 1992, Order in Docket No. P-100, Sub 114, and to all rules and regulations, if any, as other domestic public cellular radio telecommunication service providers may be subject to in North Carolina.

Cellular Express Comments. CEI identified itself as having initiated the concept of providing service to roaming cellular users operating outside their home areas or areas outside those covered by automatic roaming agreements. CEI called this their "Roamer Plus" service and described it as being very similar to the service described by Osiris. The charges are $1.25 for station calls, $2.00 for person-to-person calls, and a per-minute charge of $1.95. CEI stated that it had had correspondence with the Public Staff and that the Public Staff had raised the same objections to its service as to that of Osiris--viz., that CEI was an AOS and was ineligible for certification. CEI argued that "Roamer

Plus" is a type of cellular resale which is exempt from regulation. CEI emphasized certain key features of its service that it believed should be given weight in any analysis: the service is offered only to cellular users and is accessible only by cellular means; the end-user utilizes his own phone, not that of an aggregator; the service can only be originated on a licensed cellular system with which CEI has an agreement; there is a per-minute charge similar to other cellular resale situations; there is no commission or location surcharge; and CEI charges uniform rates which are comparable to other roamer charges.

Bearing these points in mind, CEI argued that its service is fundamentally a cellular resale service and that it is not an AOS. The cellular service it offers is acquired from the underlying carrier's system capacity and air time and is accessible only by cellular phones. There are only two differences between "Roamer Plus" and more traditional cellular resale. First, the service is offered to roamers exclusively on a call-by-call basis and, second, the unique ID of the user's transceiver is not in the data base and so must be acquired by other means by an operator to prevent fraud. These are inherent to the nature of CEI's service. CEI noted that the Public Staff did not challenge CEI's assertion that Roamer Plus is a cellular service at least in part.

CEI further asserted that it is not a long-distance carrier in the usual sense because it is not offering a service on a subscription basis to enable a party to complete a call from one fixed telephone to another. Nor is CEI an AOS within the meaning or intent of the Commission's AOS Order. CEI cited two basic distinctions:

1. Roamer Plus does not serve transient venues of the sort contemplated by the Order.

2. There is an identity between the customer and end-user; no aggregator is involved.

CEI further stated that it pays no commission to anyone. The underlying carrier is paid a per-minute charge for access to the system, but this is not comparable to a commission. CEI also emphasized that it charges reasonable rates comparable to those charges to cellular roamers covered by automatic roaming agreements. For all these reasons, CEI argued that its service would be in the public interest.

Cellular One Comments. Cellular One is the licensee for NC3RSA and professed familiarity with CEI's "Roamer Plus" service, which is similar to Osiris's proposed service. Cellular One endorsed the "Roamer Plus" service as advantageous to customers and in the public interest.

Reply Comments

GTE Mobilnet. GTEM filed reply comments specifically to take issue with the Public Staff's assertion that allowing Osiris to operate would remove an incentive for cellular carriers to negotiate reciprocal roaming agreements. GTEM stated that it had reciprocal roaming agreements with the vast majority of cellular carriers in the United States and that such agreements gave carriers with such agreements a competitive advantage. GTEM argued that the services proposed by Osiris do not arise out of the absence of such agreements. Rather, the services proposed by Osiris arise out of an industry-wide fraud problem.

GTEM explained that when a cellular call is made by a roamer, his NPA/NXX is compared to those of carriers with whom that carrier has a reciprocal roaming agreement. If an agreement is in place, the call is completed. At the same time, the roamer's electronic sense number (ESN) is routed to one of two national clearinghouses to further validate the roamer as a customer of his carrier. However, there is a time delay of about 15 minutes, and cellular carriers permit all roamer calls in the interim as long as the initial NPA/NXX checks out. Sophisticated criminals utilize this time delay to select "valid" NPA/NXXs and phony ESNs using random number generators. To combat this fraud, cellular companies have chosen to block roamer calls from NPA/NXXs which have been identified as a source of a high incidence of fraud. GTEM said this is a void that Osiris is seeking to fill. GTEM further indicated that within 12 months technology will permit virtually instantaneous ESN validation before the first call is completed.

Cellular Express. CEI made the following arguments in its reply comments:

1. The services described by Osiris and CEI are new types of service not specifically contemplated by the Commission when it deregulated cellular services or when it established the AOS policy.

2. The Commission's decision to exempt cellular carriers and resellers from regulation should be interpreted broadly rather than narrowly. The Public Staff's interpretation that this was intended to cover only carriers licensed by the FCC and cellular resellers that buy "basic service" from their underlying carriers is cramped and insupportable. CEI pointed out that the Commission itself has found cellular service to be a "nonessential, discretionary service." The purpose of regulation is to protect users, not handicap carriers; and the Commission has already determined that "consumers of cellular service have available other adequate remedies in the marketplace."

3. The proper classification of the service should be based on the essential character of the service from the standpoint of the user rather than the manner in which the service is billed. CEI maintained that its service has more in common with cellular resale than any other telecommunications service, including AOS.

4. The Commission's AOS Order did not intend to embrace cellular service to mobile users. While certainly users of this service are "transient," they are not transient users within the context of the AOS Order.

5. The Public Staff analogy to long-distance carriers is misplaced and without merit.

6. The offering of these services is in the public interest. In addition to the fraud considerations pointed out by GTEM, CEI pointed out that it is costly for cellular carriers to construct and maintain data bases on a regular basis. CEI is offering Roamer Plus in the vast majority of states; and in most jurisdictions, it has been found to be exempt from regulation as cellular services.

7. If the Commission deems that the service is allowable, but with restrictions, those proposed by BAM are acceptable.

Osiris. Osiris contended in its reply comments that there is a demonstrated need for the services it is proposing. Osiris said that in May 1993 there were over 20,000 attempted "B-side" intrastate cellular roaming calls that could not be completed from the Raleigh-Durham, Greensboro, Fayetteville, Burlington, and Asheville MSAs. Authorizing Osiris's service will increase network utilization and drive the cost of cellular transmission down.

Osiris further contended that its service is a cellular roaming service comparable to that offered to roamers pursuant to carriers' reciprocal roaming agreements. Osiris noted that the cellular carrier picking up a roaming call does not have a continuing monthly contractual relationship with the end-user any more than Osiris does. Similarly, Osiris's contractual relationship with the underlying carrier is the same type of relationship that the roamer's home cellular provider has with foreign carriers pursuant to reciprocal agreement. Furthermore, no cellular carrier is required to provide equal access.

Osiris argued that it qualifies as a cellular reseller. Simply because it intends to pass through the charges for cellular airtime does not disqualify it from this status. Osiris also argued that it is not an AOS. For one thing, it provides service and a choice of billing options directly to the end-user, and its services do not involve an aggregator. Whereas a payphone provider or a motel has the ability to provide telecommunications service without an AOS, many cellular users roaming outside their home CGSAs literally cannot complete a call without this proposed service.

Osiris denied that its service would result in higher roamer rates. An eight-minute call would cost $13.85. A nationwide range for such a call under reciprocal agreement would be $7.60 to $16.20.

Osiris also replied to the comments of BAM, which requested that the Commission adopt certain restrictions. Osiris opposed BAM's suggestion regarding unaffiliated roamers; stated that it is billing end-users directly; and noted that the cellular user can choose not to use the service and can request information.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

This petition for declaratory ruling presents a question of first impression to the Commission as to whether a company providing operator services to cellular roamers wishing to originate calls, where reciprocal roaming agreements are inapplicable, is lawful in North Carolina. To make this determination, the Commission must decide whether the petitioner--in this case, Osiris--is a cellular reseller and whether and to what degree the Commission's Order Exempting Domestic Public Cellular Radio Telecommunications Service Providers from Regulation of February 14, 1992, (cellular deregulation Order) should apply. A further question the Commission must consider is the applicability of the Commission's October 21, 1988, Order Finding Intrastate Certification of Alternative Operator Services Is Not in the Public Interest (AOS Order).

After careful consideration of the filings in this matter, the Commission reaches the following conclusions:

1. Osiris should be classified as a cellular reseller. Osiris specializes in providing operator services to cellular roamers in areas where reciprocal roaming agreements are inapplicable.

2. Osiris is not an AOS within the meaning of the AOS Order.

3. The cellular deregulation Order provides for the exemption of cellular carriers and cellular resellers from most regulation upon a finding of competitiveness and public interest.

4. Cellular resellers specializing in providing operator services occupy a niche in an otherwise competitive industry and are subject to competitive pressures from that industry's market. The Commission believes that it is in the public interest to subject such cellular resellers to the same degree of regulation as other cellular resellers.

The Commission is persuaded that Osiris and those providing similar service should be classified as cellular resellers. This particular class of cellular reseller specializes in providing operator services to roamers wishing to originate calls in MSAs where reciprocal roaming agreements are inapplicable and, as such, this class of reseller does not offer a full range of service, including basic service. The Commission does not believe that this should disqualify Osiris from reseller status. The Commission does not find the Public Staff's analogy likening the pass-through of cellular charges to IXC access charges to be convincing. The fact of the matter is that these calls are being originated from a cellular phone and are being carried in whole or in part over a cellular network just like other cellular calls. This entire market niche is a function of the existence of a cellular marketplace. Osiris is, moreover, providing a means of completing cellular calls which would not be completed otherwise--a service which, other things being equal, is clearly in the public interest.

The Public Staff has maintained that Osiris is an AOS and is thus ineligible to operate in North Carolina on an intrastate basis. The Commission disagrees. The AOS Order defines an AOS as an <u>interexchange carrier</u> that specializes in providing operator services to a transient venue. Osiris and those providing similar service are not interexchange carriers; they are cellular resellers. Therefore, the AOS Order cannot logically apply to them. The Commission, however, does emphasize that the decision in this case does not affect the integrity of the AOS Order as it applies to interexchange carriers.

In addition, while there are certain analogies that can be drawn between the services offered by Osiris and those of an AOS, there are differences as well. For instance, both Osiris and AOSs are providing operator services to transient venues. On the other hand, the transient venues are not identical, one being a cellular car phone owned by the roaming end-user and the other a hotel, motel, or payphone. With AOSs there is typically an aggregator involved. With Osiris, there is no aggregator as such, although the cellular carrier with whom Osiris contracts may be analogous in some respects. More importantly, in the AOS Order, the Commission noted end-user captivity. Here, there is a degree of captivity in that the caller may have only one choice to make this particular type of call. But, the Commission also relied heavily in its AOS Order on the historical record of the AOS industry of customer abuses and high rates. Here, there is no such record. At this point, the rates proposed by Osiris appear generally comparable to those charged under reciprocal roaming agreements, and there have been no indications of widespread end-user abuse.

The cellular deregulation Order exempts cellular carriers and cellular resellers from most forms of regulation, including certification requirements and complaint jurisdiction. The authorizing legislation, G.S. 62-125, empowered the Commission to deregulate cellular carriers "to the extent it finds such services to be competitive and such action in the public interest." The Commission in its cellular deregulation Order found the overall cellular market to be generally competitive and deregulation to be in the public interest. In the case of service areas where at that time only one facilities-based cellular carrier was in operation, the Commission found that the operation of a second carrier was inevitable and noted that the potential of competition would act to prevent monopolistic abuse. One rationale that the Commission particularly relied on in making the public interest determination is that "cellular service is a nonessential, discretionary service." The Commission, of course, retains the authority to reconsider or modify the degree of deregulation.

In the real world, competition is seldom perfect. It is certainly true that competition among cellular carriers is not perfect competition. However, the standard of G.S. 62-125 is not one of perfect competition. Rather, the important point is whether there exists a sufficient degree of competition to restrain monopolistic abuses.

In the instant case, there is ostensibly exclusive access by Osiris or some other similar carrier to the roamer desiring to make a certain kind of call. It must be recalled, however, that this service is being offered within the context of a competitive industry. It is, therefore, not surprising that even here monopolistic abuses are restrained by competitive pressures.

The most apparent competitive pressure is the spread of reciprocal roaming agreements. The underlying cellular carriers are under constant pressure to provide better service to their customers by expediting and simplifying the way cellular customers can talk to each other. An exploitative cellular operator service will tend to alienate customers from itself and from the carrier it is contracting with. To the extent that this happens, there will be that much more incentive for the cellular carrier to conclude reciprocal roaming agreements, thereby reducing the market for the cellular operator service. Moreover, there appear to be other reasons apart from customer alienation that will tend to expedite the conclusion of reciprocal roaming agreements. A complete system of reciprocal roaming agreements is an obvious rationalization to a currently incomplete system. In addition, to the extent that cellular operator services exist because of technical limitations on the detection of cellular fraud as suggested by GTEM, improved technology--which is said to be just over the horizon--will tend to shrink the opportunities for cellular operator services.

Although it is hazardous to predict exactly how telecommunications will evolve, it is not unreasonable to suggest that this particular market niche is a precarious one, headed, perhaps, for eventual extinction with the advent of a complete system of reciprocal roaming agreements. In order to stave off or at least delay these developments, cellular operator services will be forced to charge reasonable rates and provide good service. The Commission accordingly finds that cellular resellers specializing in operator services are subject to competitive conditions and subsist within the context of a competitive industry and that it is in the public interest to subject them to no greater degree of regulation than other cellular resellers.

Nevertheless, the Commission would note that the cellular deregulation Order specifically provides that the Commission retains "the right to reassert its jurisdiction over cellular carriers at any time upon petition of any interested party for good cause shown." Should the cellular resellers specializing in providing operator service in these circumstances engage in conduct which is not in the public interest, the Commission has the authority to promulgate appropriate regulation.

IT IS, THEREFORE, ORDERED that the cellular service proposed by Osiris be declared to be exempt from regulation pursuant to the cellular deregulation Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of July 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-354, SUB 129

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request by Carolina Water Service, Inc., of North Carolina to Reduce its Rates for Water Utility Service to Customers in the Pine Knoll Shores Service Area who are Located within the Boundaries of the Town of Atlantic Beach	)	ORDER DENYING PETITION TO REDUCE RATES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Laurence A. Cobb, Presiding; Chairman John E. Thomas, Commissioner Judy Hunt

APPEARANCES:

For Carolina Water Service, Inc., of North Carolina

Edward S. Finley, Jr., Hunton & Willliams, Attorneys at Law, P. O. Box 109, Raleigh, North Carolina 27602

For the Public Staff:

A. W. Turner, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North carolina 27626-0510
For: The Using and Consuming Public

BY THE COMMISSION: On September 22, 1993, Carolina Water Service, Inc., of North Carolina (CWS) filed a petition in this docket requesting authority to reduce its rates and charges for water utility service provided to its customers in its Pine Knoll Shores service area who are also within the municipal limits of Atlantic Beach. On October 13, 1993, the Commission issued an Order scheduling the petition for hearing as a complaint proceeding pursuant to G.S. 62-74. A hearing was scheduled for December 8, 1993, in Raleigh, and prefiled testimony was required.

On October 19, 1993, the Public Staff filed its Motion to Reschedule Hearing. The Public Staff asserted that it had no objection to the date of hearing, but that the hearing should be held in or near the service area and that all Pine Knoll Shores customers should be given notice of the hearing. The Commission denied the Motion to reschedule the hearing to the Pine Knoll Shores area but required the Company to provide notice to all its customers in the Pine Knoll Shores area, whether within the municipal limits of Atlantic Beach or not.

The hearing was held as scheduled. David Hasulak, a member of the Pine Knoll Shores Town Council, appeared as a public witness and opposed the different rates within the service area. Carl J. Wenz testified for the Company, and Kenneth E. Rudder testified for the Public Staff.

Based on the evidence presented at the hearing and the records of the Commission, the Commission finds and concludes as follows:

FINDINGS AND CONCLUSIONS

The Commission finds and concludes that its decision in Docket No. W-354, Sub 126, should be reaffirmed. We agree with the Public Staff that it would not be advisable in the context of this docket to begin what may be a piecemeal dismantling of the Company's uniform rate structure prior to a full policy review and decision regarding whether uniform rates continue to be in the public interest. The Commission agrees with the Public Staff that the most appropriate proceeding in which to consider the matter of a rate reduction for some of the customers served by the Pine Knoll Shores water system is the next general rate case filed by CWS which is currently pending before the Commission in Docket No. W-354, Sub 128. A rate reduction for only part of the customers, while leaving the remaining customers at existing rates, raises substantive issues of rate discrimination among customers in the same class that can best be addressed in a general rate case. Accordingly the peitition for rate reduction filed by CWS on September 22, 1993, is denied.

IT IS, THEREFORE, ORDERED that the petition to reduce rates filed in this docket by Carolina Water Service, Inc., of North Carolina on September 22, 1993, is denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of December 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-1026

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Bradfield Farms Utility Company, Post Office Box 127, Sherrills Ford, North Carolina 28673, for a Certificate of Public Convenience and Necessity to Provide Water and Sewer Utility Services in the Bradfield Farms and Silverton Subdivisions, Mecklenburg and Cabarrus Counties, and for Approval of Rates	ORDER DENYING APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; ORDER TERMINATING MID SOUTH AS EMERGENCY OPERATOR; NOTICE TO PACE AND WHITLEY

HEARING IN: Conference Center, Room 267, Charlotte-Mecklenburg Government Center, 600 E. Fourth Street, Charlotte, North Carolina, on May 25, 1993; and

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on May 27 and June 24, 1993

WATER AND SEWER - AMENDED AND DENIED

BEFORE: Commissioner Charles H. Hughes, Presiding; and Commissioners William W. Redman, Sarah Lindsay Tate, Julius A. Wright, Robert O. Wells, Laurence A. Cobb, and Allyson K. Duncan

APPEARANCES:

For the Applicant:

Robert F. Page, Crisp, Davis, Page, Currin & Nichols, Suite 400, 4011 WestChase Boulevard, Raleigh, North Carolina 27607-3944
Appearing for: Mec-Cab Utilities, Inc. and Bradfield Farms Utility Company

Joseph W. Eason and Louis S. Watson, Jr., Moore & Van Allen, Post Office Box 26507, Raleigh, North Carolina 27609
Appearing for: Crosland Utilities, Inc., and John Crosland Company

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, and Robert B. Cauthen, Jr., Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

For Carolina Water Service, Inc. of North Carolina:

Edward S. Finley, Jr., Hunton and Williams, Attorneys at Law, Post Office Box 109, Raleigh, North Carolina 27602

BY THE COMMISSION: On December 11, 1992, Bradfield Farms Utility Company (Bradfield or Applicant) filed an application in this docket for a certificate of public convenience and necessity to provide water and sewer utility services in the Bradfield Farms and Silverton Subdivisions in Cabarrus and Mecklenburg Counties, and for approval of rates. Simultaneously with its application, Bradfield filed a motion for temporary or emergency authority to operate the water and sewer utility facilities in the Bradfield Farms, Silverton, and Britley Subdivisions on a temporary or emergency basis. By Orders of November 10 and December 11, 1992, the appointment of Mid South as the emergency operator in these three subdivisions was extended pending further Order of the Commission. Docket No. W-720, Subs 96 and 108.

The subject application is the outcome of proceedings in Docket No. W-720, Subs 96 and 108, in which the Commission, on July 28, 1992, revoked the temporary operating authority of Mid South Water Systems, Inc. (Mid South), in Bradfield Farms Phases III, IV, and V, and declared Mid South's extension into the Silverton Subdivision unauthorized. On December 3, 1992, the Commission revoked the franchise of Mid South to provide Bradfield Farms Phase II with water and sewer services.

The Order of July 28, 1992, also denied Mid South's application to serve the Britley Subdivision (Docket No. W-720, Sub 108).

On February 19, 1993, Carolina Water Service, Inc. of North Carolina (CWS) moved to intervene in this docket on the basis of its participation in the predecessor docket, Docket No. W-720, Subs 96 and 108. CWS's motion was granted on April 13, 1993.

Hearings were held in this matter on May 25, 1993, in Charlotte, and on May 27 and June 24, 1993, in Raleigh. Applicant Bradfield and Mec-Cab Utilities, Inc. (Mec-Cab) presented the testimony of Jocelyn M. Perkerson. Crosland Utilities, Inc. (Crosland Utilities) and John Crosland Company (John Crosland) presented the testimony of Daniel L. Barnobi. Intervenor CWS presented the testimony of Carl Daniel. The Public Staff presented the testimony of Katherine A. Fernald and Andy R. Lee.

Subsequent to the hearings, the terms of service of Commissioners Sarah Lindsay Tate, Robert O. Wells, and Julius A. Wright expired on June 30, 1993, and those Commissioners did not participate in deciding this case.

Based on the foregoing, the testimony and exhibits offered at the hearing and the entire record in this proceeding, and the judicial notice of certain dockets herein described, including Docket No. M-100, Sub 113, the Commission makes the following

FINDINGS OF FACT

1. On December 11, 1992, Bradfield filed an application for a certificate of public convenience and necessity to provide water and sewer utility services in the Bradfield Farms and Silverton Subdivisions in Cabarrus and Mecklenburg Counties, and for approval of rates. (As of the date of this Order an application to serve the Britley Subdivision has not been filed.)

2. The Applicant, Bradfield, is a Joint Venture. Two new corporations are the partners of the Joint Venture: Crosland Utilities and Mec-Cab. Crosland Utilities is a North Carolina corporation that is a wholly-owned subsidiary of John Crosland. Mec-Cab is a wholly-owned subsidiary of Mid South.

3. Under the Joint Venture agreement, Mec-Cab is to transfer $1,749,370 of utility property to Bradfield.

4. Under the Joint Venture agreement, Crosland Utilities will invest $10,000 in the Joint Venture.

5. A Sales and Construction Agreement between Bradfield and John Crosland requires Bradfield to enter into contracts with John Crosland for the construction of utility additions.

6. A Utility Operating Agreement between Bradfield and Mid South would require Bradfield to employ Mid South as the day-to-day operator of the Bradfield water and sewer systems.

7. Under an escrow agreement, John Crosland will deliver an irrevocable letter of credit in the amount of $250,000 to an escrow agent, and Mid South will deliver an irrevocable, unconditional letter of credit in the amount of $150,000 to an escrow agent. The letters of credit are intended to secure the payment of

any income taxes on contributions in aid of construction (CIAC) that might arise as a result of John Crosland [or its predecessor, Centex Real Estate Corporation (Centex)] having made taxable contributions of utility property to Mid South in the Bradfield Subdivision.

8. Under the Joint Venture agreement, Mec-Cab is required to purchase all of John Crosland's interest in the venture as of the later of ten years from the date of formation of the venture or when John Crosland has disposed of all of its property within Bradfield Farms, but in no event later than 15 years from said date of formation.

9. Under the Joint Venture agreement, Mid South is the operator of the Bradfield systems, and, through Mec-Cab, is the owner of 50% of Bradfield. As previously indicated, Mid South is obligated to contribute certain water and sewer property to Bradfield.

10. By Order of July 28, 1992, issued in Docket No. W-720, Subs 96 and 108, this Commission found that Mid South had not carried the burden of proof as to its ability from the standpoint of financial fitness to provide water and sewer services in the Britley Subdivision and certain phases of the Bradfield Farms Subdivision.

11. In its Order of July 28, 1992, in Docket No. W-720, Subs 96 and 108, the Commission found that Mid South had failed to provide certain information as requested by the Public Staff. This information included Mid South's contract with Crosland/Centex regarding tap fees and construction costs. Mid South was also found to have violated a Commission Order regarding extension of certain of its plant facilities into Bradfield Phases III, IV, and V.

12. In its Order of July 28, 1992, the Commission determined that, based on Mid South's 1990 annual report, "under a worst case scenario" Mid South's CIAC tax liability "would be in the range of $534,000 before consideration of any penalty or interest that might be due." This was based on $1,364,000 of taxable CIAC including contributions from John Crosland.

13. As a result of the CIAC tax issue and deficiencies in Mid South's reports to the Commission, in its Order of July 28, 1992, this Commission determined that: "The fact that this Company appears to be 100 per cent debt financed, the fact that current liabilities appear to exceed current assets by $189,000, the fact that the Company's current liabilities appear to exceed its liquid assets (i.e., cash and cash equivalents) by $1,751,000, the fact that the Company's current liabilities appear to exceed its liquid assets and its accounts receivable by $1,170,000, the fact that the Company appears to have a negative net worth together with the fact that Mid South appears to have been financially unable to make payment of taxes withheld from employees to the IRS in a timely manner, not to mention the fact that Mid South faces an unrecorded potential income tax liability of $534,000 related to taxable CIAC, all raise serious doubts as to the Company's continuing financial viability unless some action is taken to improve its financial health. The Commission's decision, as set forth herein, may relieve some of the financial strain under which the Company now appears to be operating."

14. In the Commission's September 11, 1992, Order in Docket No. W-720, Subs 96 and 108, denying Mid South's petition for rehearing of the July 28, 1992, Order, the Commission noted that Mid South continued to argue that there was little or no tax liability from its receipt of CIAC from John Crosland and other developers. Yet, according to the Commission, these "continued representations run counter to the Internal Revenue Service and Commission pronouncements on this issue. The burden is upon Mid South to show that it has no tax liability. It has not done so. It does not ease the Commission's concern over the failure of Mid South to properly account for CIAC, that if, as Mid South asserts, the IRS decides to collect CIAC taxes from Mid South, such action would not result in any forced collection action for an estimated three to five years after all appeals and litigation options were exhausted. It is the purpose of the Commission's orders with respect to CIAC to prevent the utilities under its jurisdiction from being faced with a forced collection that would imperil service to its customers."

15. In the same September 11, 1992, Order this Commission considered an as yet incomplete proposal under which the CIAC tax would be paid from funds due Mid South in an escrow account. This Commission expressed concern that "Mid South in effect may be agreeing to pay the taxes if the developer fails to fulfill its obligations."

16. In its Order Revoking Franchise In Bradfield Farms Phase II, issued on December 3, 1992, in Docket No. W-720, Subs 96 and 108, this Commission reiterated its belief that Mid South is not financially sound, and that Mid South should cooperate with the Commission to "facilitate an orderly transfer of applicable operating authority for and ownership of said systems to a qualified operator."

17. At the June 24, 1993, hearing in this docket, Applicant witness Perkerson testified that no CIAC taxes had been paid on the property to be contributed by Mec-Cab to Bradfield.

18. Applicant witness Perkerson testified that it was the Applicant's position that the IRS would not require anyone to pay the tax. She further testified that the basis for this determination was discussed with people that represent water and sewer utilities in Washington and that it was their view that the tax will be rescinded with retroactive effect.

19. Applicant witness Perkerson testified that the total amount of the letters of credit ($400,000) to be acquired by John Crosland and Mid South was partly based on an assumption that the IRS would negotiate any liability downward. Witness Perkerson estimated that $400,000, based on a 34% tax rate, is 75% to 80% of the CIAC tax.

20. Applicant witness Perkerson testified that Mid South had not yet acquired its $150,000 letter of credit, but that the Company had discussed the issue with bankers. Ms. Perkerson did not testify as to the cost of obtaining such a letter of credit.

21. The Joint Venture arrangement fails to satisfy Commission concerns regarding the CIAC tax due on the property contributed to Mid South in Bradfield. Despite the fact that Crosland is willing to obtain a letter of credit in the amount of $250,000, any additional tax must be paid by Mid South.

22. The Joint Venture agreement provides that the letters of credit cannot be released until there has been a formal determination of CIAC tax liability by a United States Tax Court or United States District Court. Acceptance of this proposal would create a situation where customers could be harmed by enforcement action of federal authorities. It would also create a period of uncertainty, lasting several years, in which the financial standing of Mid South, the operator and one-half owner of the Applicant, would be exceedingly tenuous at best.

23. The appointment of Mid South as emergency operator should terminate no later than 60 days after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT

This docket concerns the application of Bradfield Farms Utility Company for a certificate of public convenience and necessity to serve the Bradfield Farms and Silverton Subdivisions in Mecklenburg and Cabarrus Counties and for approval of rates. The application was filed on December 11, 1992.

Bradfield is a joint venture partnership whose partners are Mec-Cab and Crosland Utilities. Mec-Cab is a wholly-owned subsidiary of Mid South and Crosland Utilities is a wholly-owned subsidiary of John Crosland.

John Crosland is the developer of the Bradfield Farms Subdivision. The Silverton Subdivision, which is adjacent to the Bradfield Farms Subdivision, is being developed by Stephen Pace. (The Whitley Construction Company is the developer of the Britley Subdivision.)

This matter arose as a result of the Commission's decision (1) revoking Mid South's temporary operating authority in Bradfield Farms Subdivision Phases III, IV, and V; (2) declaring Mid South's extension of service into the Silverton Subdivision unauthorized; and (3) revoking a franchise previously awarded to Mid South to serve Bradfield Farms Subdivision Phase II. The Commission took the foregoing action as a result of Mid South's failure to carry the burden of proof as to its ability, from the standpoint of financial fitness, to provide public utility service within the aforesaid subdivisions (Docket No. W-720, Subs 96 and 108).

Although the Commission recognizes that the application in this matter has technically been advanced by a new entity, this entity is owned and operated by the two interests, John Crosland and Mid South, that have been the focus of the Commission's earlier inquiries in Docket No. W-720, Subs 96 and 108. Under the circumstances, the Commission finds that it would be inappropriate to ignore the long history of such proceedings.

An inquiry into the financial fitness of the Applicant must therefore consider the financial standing and responsibilities of its owners, John Crosland and Mid South, who appear through affiliates as the Joint Venturers for the Applicant, Bradfield. The evidence indicates that Crosland Utilities and/or John

Crosland is willing to provide $10,000 in capital for the venture, to obtain a letter of credit for the benefit of Mid South's CIAC tax obligations in the amount of $250,000, and to share equally future cash obligations with Mec-Cab. Mid South (through Mec-Cab) is to contribute more than $1.7 million in facilities, is to obtain a $150,000 letter of credit for CIAC taxes, is to operate the system directly, and is to be responsible for one-half of all future costs of the utility. Apparently, Mec-Cab will not possess any assets separate from those owned by the Joint Venture.

An examination of the proposed arrangement, and the responsibilities it entails for Mid South, reveals continuing concerns and ultimately its unacceptability, particularly when viewed in conjunction with previous Orders of the Commission. Mid South, it bears repeating, has not shown that it is financially fit to operate the subject systems. Nothing in this application changes that fact. There is no infusion of capital to Mid South. All of the evidence is that even with John Crosland's letter of credit, Mid South, the operator of the systems, potentially faces hundreds of thousands of dollars of CIAC tax liability arising out of the contributions to it of the Bradfield properties. The Commission is concerned that the amount of this tax liability is as yet unascertained. But whatever its precise amount, the obligation is substantially more than the $400,000 provided in the proposed letters of credit. Moreover, as the owner of Mec-Cab, Mid South is also liable for one-half of the debts of the Joint Venture. There has been no evidence that Mec-Cab has any assets, except the facility assets of Mid South which it intends to donate immediately to the Applicant. In addition, the witness for John Crosland testified that it was his intention that his Company would not be responsible for more than 50 percent of the expenses of the Applicant, even if Mid South became bankrupt.

From its structure, it appears that the proposed arrangement attempts to marginally satisfy Commission concerns regarding the financial fitness of the Applicant. Indeed, the Applicant has acknowledged that it was set up in order to satisfy the financial viability test failed by Mid South in Docket No. W-720, Subs 96 and 108. However, it has not done so.

One of several aspects of the Joint Venture agreement that is of considerable concern to the Commission is the provision requiring Mec-Cab, the Mid South subsidiary, to purchase John Crosland's interest in the Applicant. This arrangement circumvents the Commission's Orders relative to Mid South while allowing the developer, John Crosland, to avoid full responsibility for the CIAC tax. Although it has not shown that it is financially fit, Mid South would be allowed to operate the systems. There are also provisions in the Joint Venture agreement which require or allow Mid South to ultimately purchase John Crosland's interest in the Applicant. Such provisions place a significant financial burden on Mid South. This is a burden that Mid South has not shown that it is financially fit to bear.

The principal assets of the Applicant consist of facilities on which CIAC taxes are due. The only provision made to pay such taxes are proposed letters of credit that appear to be insufficient to satisfy the CIAC tax liability. Mid South, the one-half owner and the sole operator of the systems, is responsible for the difference. It appears that a fundamental consideration behind the proposed arrangement is the assumption that the CIAC tax will not be collected.

That assumption has been squarely rejected by the Commission, is contrary to federal law and IRS pronouncements, and is one of the major reasons Mid South does not now hold certificates of public convenience and necessity to provide water and sewer utility services in the subject subdivisions.

Another assumption that appears from the application and the evidence in support thereof is that the Commission, but for the CIAC tax problems, is satisfied with Mid South's financial condition. Such an assumption is incorrect. As indicated by Orders issued in the past year, the Commission has significant, continuing concerns with regard to Mid South's overall financial viability. In addition to Docket No. W-720, Subs 96 and 108, the Commission hereby takes judicial notice of the following dockets which are related to the Commission's continuing concerns relating to Mid South's financial condition: Docket No. W-100, Sub 21, In the Matter of Audits and Analyses of the 1992 Annual Reports of Mid South Water Systems, Inc., Surry Water Company, Inc., H. C. Huffman Water Systems, Inc., Old South Water System, Inc., and Lincoln Water Works, Inc.; and Docket No. W-314, Sub 26, In the Matter of Application by Surry Water Company, Inc., for a Certificate of Public Convenience and Necessity to Furnish Water Utility Service in Bishops Ridge Subdivision in Forsyth County, North Carolina and for Approval of Rates.

Under the application currently before the Commission, Mid South will be the contract operator of the subject systems. Therefore, the financial condition of Mid South continues to be of paramount importance to the Commission. No party to the proceeding has presented evidence demonstrating the financial fitness of Mid South to serve as contract operator. In the absence of such a showing, the Commission cannot and will not grant the franchise requested by the Applicant in its instant application. Further, the Commission cannot allow the Applicant and its owners to ignore reasonable requirements regarding financial fitness by the use of devices, such as those proposed in the instant application, which are contrary to the spirit and intent of the Public Utilities Act and Commission policy as expressed in its numerous Orders discussed above.

As indicated above, Mid South has previously failed to show that it is financially fit to operate these systems (Docket No. W-720, Subs 96 and 108). Its participation in the Joint Venture appears to diminish its financial standing further by requiring it to reconvey its full ownership in property without cash compensation and to become a potential debtor to John Crosland, for which, through Mec-Cab, it will be responsible for one-half of any debts of the Applicant. Also, Mid South, under the Joint Venture agreement, ultimately has the responsibility of purchasing John Crosland's interest in the Joint Venture. That requirement causes concern to the Commission due to the additional financial burden it places on Mid South. While greater protection under the proposed plan is provided for Bradfield Farms customers with John Crosland's participation, Mid South is still exposed to substantial financial risk. During this proceeding, Mid South has failed to show that it is financially fit. Given Mid South's operational and part ownership responsibilities, this necessarily raises serious concerns regarding the financial fitness of Mec-Cab (which apparently will not have any independent assets) and of the Applicant. Such concerns have not been allayed by the evidence presented in this proceeding.

Finally, the Commission will also order Mid South to reconvey all of its public utility property interests in the Bradfield Farms, Silverton, and Britley

Subdivisions to John Crosland and the other appropriate developers. Such reconveyance should relieve Mid South of the potential income tax liability with which it is now confronted as a result of having received substantial amounts of taxable CIAC from developers within the subject subdivisions. Once Mid South has eliminated the possibility of its having to satisfy the instant, onerous CIAC tax obligation that it does not have the financial resources to meet, its financial condition will be dramatically improved to a degree such that it will be much better able to operate and otherwise function as a financially viable public utility enterprise.

Based upon the foregoing and the entire evidence of record, the Commission finds and concludes that the application filed by Bradfield for a certificate of public convenience and necessity to provided public utility water and sewer services in the Bradfield Farms and Silverton Subdivisions should be denied.

APPOINTMENT OF EMERGENCY OPERATOR

The Commission's Order of July 28, 1992, in Docket No. W-720, Subs 96 and 108, and subsequent Orders, granted Mid South emergency operating authority pursuant to G.S. 62-116(b) in Britley Subdivision, Bradfield Farms Phases II, III, IV, and V, and Silverton Subdivision, in order to prevent the actual loss of water and sewer service in these subdivisions pending further development in these dockets and further order of the Commission. At a conference on October 28, 1992, Mid South and John Crosland advised the Commission that they would be filing an application, which is the subject of this instant docket, by the end of the year. Subsequent to the filing of the application in this docket, Mid South's appointment of emergency operator was continued pending hearing and decision. As a result of the decision entered in this Order, the Commission is of the opinion that the appointment of Mid South as emergency operator in the above-named subdivisions should terminate no later than 60 days after the date of this Order. John Crosland, either singly, or jointly with the developers of Silverton and/or Britley, shall be ordered, within 10 days of the date of this Order, to file with the Commission a statement indicating a willingness to serve as emergency operator of the water and sewer systems affected by this Order. In the event that John Crosland or the developers for the Britley and Silverton Subdivisions, or both, fail to comply with this provision, or state an unwillingness to serve as emergency operator, the Commission on its own motion will undertake to appoint an emergency operator for these systems.

IT IS, THEREFORE, ORDERED as follows:

1. That the application of Bradfield for a certificate of public convenience and necessity to provide water and sewer utility services in the Bradfield Farms and Silverton Subdivisions and for approval of rates shall be, and hereby is, denied.

2. That, within 30 days after the date of this Order, all of Mid South's public utility property interests in the Bradfield Farms, Silverton, and Britley subdivisions shall be reconveyed to John Crosland and the other appropriate developer(s). Further, Mid South shall file a written report with the Commission no later than 45 days from the issuance date of this Order identifying all properties transferred pursuant to this Ordering Paragraph and indicating full compliance with this Order.

3. That John Crosland, either singly, or jointly with the developers of the Silverton and/or Britley Subdivisions, shall file within 10 days of the issuance date of this Order, a statement indicating a willingness to be appointed as emergency operator of the water and sewer systems now serving the Bradfield Farms, Silverton, and Britley Subdivisions. In the event John Crosland and the developers in Britley and/or Silverton Subdivisions fail, either singly, or jointly, to comply with this provision, or state an unwillingness to serve as emergency operator, the Commission will undertake to appoint an emergency operator or operators for said systems.

4. That Mid South's appointment as emergency operator in the Bradfield, Silverton, and Britley Subdivisions shall terminate no later than 60 days after the date of this Order upon the appointment of a successor emergency operator or operators by the Commission.

5. That within 60 days after the date of this Order: John Crosland shall file, or cause to be filed, an application for a certificate of public convenience and necessity in the Bradfield Subdivision; Pace Development Group shall file, or cause to be filed, an application for a certificate in the Silverton Subdivision; and Whitley Construction Company shall file, or cause to be filed, an application for a certificate in the Britley Subdivision.

6. That a copy of this Order shall be mailed to R. Stephen Pace, Pace Development Group, 6719C Fairview Road, Charlotte, North Carolina 28210, and William Whitley, Whitley Construction Company, 8224 E. Harris Boulevard, Charlotte, North Carolina 28227, by the Chief Clerk by United States Certified Mail. Pace Development Group and Whitley Construction Company are hereby declared party respondents for the purpose of receiving notice of this Order and complying with the provisions of the ordering paragraphs above.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. W-1027

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Forsyth Water Company, Inc., Post Office Box 127, Sherrills Ford, North Carolina 28673 for a Certificate of Public Convenience and Necessity to Furnish Water Utility Service in Bishops Ridge Subdivision in Forsyth County, North Carolina and for Approval of Rates	ORDER DENYING APPLICATION FOR FRANCHISE

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on February 17, 1993

BEFORE: Commissioner Allyson K. Duncan, Presiding; Chairman William W. Redman, Jr., and Commissioners Sarah Lindsay Tate, Laurence A. Cobb, Julius A. Wright, Robert O. Wells, and Charles H. Hughes

APPEARANCES:

For the Applicant:

Robert F. Page, Crisp, Davis, Page, Currin, and Nichols, Suite 400, 4011 Westchase Boulevard, Raleigh, North Carolina 27607

For the Using and Consuming Public:

Paul L. Lassiter, Public Staff, North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0510

BY THE COMMISSION: On December 23, 1992, Forsyth Water Systems, Inc. (Forsyth) filed an application for a certificate of public convenience and necessity and for approval of rates for water service in Bishops Ridge Subdivision, in Forsyth County. This matter was set for hearing on Wednesday, February 17, 1993, at 2:00 p.m., in the Commission's Hearing Room, Room No. 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

The hearing came on as scheduled. Forsyth presented the testimony of Jocelyn M. Perkerson, Vice President of Finance and Regulatory Affairs. Ms. Perkerson was the only witness in this proceeding.

At the close of the hearing, counsel for the Applicant made an oral motion requesting that the Commission grant the Applicant temporary operating authority pending final decision and approve interim rates. The Commission, by Order dated February 26, 1993, denied said motion.

Based on the application, the testimony and exhibits, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. There is a commonality of ownership of Forsyth, Mid South Water Systems, Inc. (Mid South), and Surry Water Company, Inc. (Surry). All three corporations are wholly-owned by Carroll and Mary Weber.

2. The Commission hereby takes judicial notice of its official files in the matter of Mid South's application for a certificate of public convenience and necessity to provide water and sewer utility service in Bradfield Farms and Britley Subdivisions, Docket No. W-720, Subs 96 and 108. The findings of fact and the conclusions set forth in the Commission's Order Revoking Temporary Operating Authority in Bradfield Phases III, IV, and V, Declaring Silverton Extension Unauthorized, and Scheduling Further Hearing on Bradfield II Certificate of July 28, 1992, issued in Docket No. W-720, Subs 96 and 108, are incorporated herein by reference as if fully set out and are made a part of this Order.

3. The Commission hereby takes judicial notice of its official files in the matter of Surry's application for a certificate of public convenience and necessity to furnish water utility service in Bishops Ridge Subdivision, Docket No. W-314, Sub 26. The findings of fact and the conclusions set forth in the Commission's Order Denying Franchise of November 16, 1992, issued in Docket No. W-314, Sub 26, are incorporated herein by reference as if fully set out and are made a part of this Order.

4. The findings of fact and the conclusions set forth in the Commission's Order Revoking Franchise in Bradfield Farms Phase II of December 3, 1992, issued in Docket No. W-720, Subs 96 and 108, in the matter of Mid South's application for a certificate of public convenience and necessity to provide water and sewer utility service in Bradfield Farms and Britlety Subdivisions, are incorporated herein by reference as if fully set out and are made a part of this Order.

5. Forsyth has not carried the burden of proof to establish its ability, from the standpoint of financial fitness, to provide public utility water service in the Bishops Ridge Subdivision in Forsyth County, North Carolina.

6. The application filed by Forsyth for a certificate of public convenience and necessity to provide public utility water service in the Bishops Ridge Subdivision in Forsyth County, North Carolina should be denied.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 6

The preponderance of the direct testimony presented by the only witness, Company witness Perkerson, pertained to the financial viability of Surry Water Company, Inc. (Surry). Surry had previously filed an application for a franchise to provide utility services within Bishops Ridge Subdivision. However, the Commission denied Surry's request due to the Company's having failed to carry the burden of proof as to its financial fitness.

There is a commonality of ownership of Surry and Forsyth. There is also a commonality of ownership of Surry, Forsyth, and Mid South. All three corporations are wholly-owned by Carroll and Mary Weber. Collectively, these three companies on an aggregate basis, in terms of the number of customers served, represent the third largest investor owned water and sewer utility system operating in North Carolina.

Presumably, because of (1) the commonality of ownership, (2) certain other Commission decisions recently entered concerning other utility systems owned and operated by the Webers, i.e., certain Mid South systems, and (3) Forsyth's plan to employ Surry as an outside contractor to provide substantial services to the Bishops Ridge Water System, Forsyth, as evidenced by the testimony of witness Perkerson, apparently recognized the importance of convincing the Commission of the soundness of Surry's financial condition as well as that of the Webers. Indeed, such circumstances were and are of paramount importance to the Commission.

In order to place the foregoing considerations into perspective, presented below is an overview of recent findings reached by the Commission in assessing the financial viability of Mid South and Surry, which as previously stated are public utilities wholly-owned and operated by the Webers. Forsyth's instant application is thereafter addressed with greater specificity.

Mid South Water Systems, Inc.

On July 28, 1992, the Commission issued an Order revoking the temporary operating authority of Mid South with respect to Bradfield Farms Phases III, IV, and V; declared the Silverton extension to be unauthorized; and scheduled further hearing on Mid South's fitness to continue providing services in Bradfield Farms Phase II. The Commission decision in this regard resulted from its having concluded that Mid South had not carried the burden of proof as to its financial fitness. In its Order of July 28, 1992, the Commission stated as follows:

> "Major considerations underlying the Commission's conclusion that it cannot make a determination regarding the soundness of the Company's overall financial standing, in addition to many, if not most, of the shortcomings identified by Carolina Water in its June 4, 1992, filing which the Commission finds valid, include the following:
>
> "(1) Mid South's 1990 annual report reflects net income of $131,000, but it also reflects <u>negative</u> total equity capital of $177,000 (emphasis added in original);
>
> "(2) Mid South's 1990 balance sheet reflects total net assets of $3,495,000, but another section of its 1990 annual report implies an additional $12,377,000 in assets which are not reflected on Mid South's balance sheet and which were acquired as CIAC;
>
> "(3) Mid South's 1990 balance sheet is $304,000 out of balance (debits exceed credits);
>
> "(4) Mid South's balance sheets and income statements for earlier years do not appear to exist;
>
> "(5) Under a worst case scenario and based upon information provided by the Company, Mid South's potential income tax liability arising from CIAC, before consideration of any penalty or interest that might be due, is in the range of $534,000;
>
> "(6) Mid South states that it has tax losses of $273,000 which could be used to partially offset taxable CIAC. Based on a $273,000 tax loss, the tax offset to the foregoing $534,000 tax liability would be $107,000, resulting in net tax due of $427,000;
>
> "(7) Because of the lack of information, one cannot reach an informed conclusion regarding the adequacy, or lack thereof, of Mid South's liquidity or overall cash flow; and
>
> "(8) Because of the incompleteness of the financial data provided by the Company and its apparent failure to recognize the importance of properly prepared financial statements and the importance of

organizing and maintaining financial records, it is exceedingly difficult to rely on the information which has been provided with virtually any degree of confidence."

The foregoing conclusions were reached after the Commission had repeatedly sought information from Mid South to be used in assessing the status of the Company's financial condition. As quoted in the Commission's Order of July 28, 1992, "...Mid South is either unable or unwilling to comply with the Commission's financial reporting requirements."

The Commission subsequently held hearings on Bradfield Farms Phase II, and thereafter revoked the Company's franchise for that subdivision, due to Mid South's inability to carry the burden of proof as to its financial fitness. By the time the Phase II hearings were held, the Company had filed its 1991 annual report, after having received two extensions of time. That annual report combined the operation of the Webers' construction company with its utility company (Mid South).

The Company agreed to file and did file a restated annual report for 1991 which initially appeared to be represented as that of the utility on a stand alone basis. However, the restated report continued to mix utility and non-utility operations together in certain respects. Mid South now takes the position that its 1992 annual report will not mix utility and non-utility functions. This report was initially due April 30, 1993. However, the Company requested and received a 30-day extension of time for the filing of that report. Such report is now due May 30, 1993.

Pursuant to the Commission's Order of July 28, 1993, issued in Docket No. W-720, Subs 96 and 108, a formal Commission conference was convened, with a member of the Commission Staff presiding, for the purpose of receiving comments and proposals on how the revoked franchises would be transferred to a new owner(s)/operator(s). During this hearing Mid South and John Crosland Company (John Crosland) appeared to take the position that they would form a joint venture and that the joint venture would file an application for a franchise to provide utility services within the Crosland developments. Further, it appeared that John Crosland would act as a surety for all matters affecting the providing of services in said developments.

The joint venture agreement was subsequently filed in conjunction with an application, by the joint venture partnership, for a franchise to provide utility services within the Crosland developments (Bradfield Farms Phases II, III, IV, and V; and the Silverton Subdivision). The joint venture agreement is by and between Crosland Utilities, Inc. (Crosland Utilities) and Mec-Cab Utilities, Inc. (Mec-Cab). Crosland Utilities is a wholly-owned subsidiary of the John Crosland Company and Mec-Cab is a wholly-owned subsidiary of Mid South. Bradfield Farms Utility Company (Bradfield) is the joint venture partnership created by the joint venture agreement.

Hearings on Bradfield's application for a franchise have been set for May 25, 1993, in Charlotte and for May 27, 1993, in Raleigh. However, based on a preliminary review of the Bradfield joint venture agreement, it appears that, other than an initial capital infusion of $10,000, no financial responsibility has been shifted to or assumed by John Crosland or its affiliate(s). The agreement does expressly place significant financial responsibilities on Mec-Cab. For example, the agreement provides that "...Mec-Cab shall also make future cash contributions to the Partnership to the extent the same are required to fund all cash shortfalls and to pay all obligations in excess of the revenues received by the Joint Venture in the operation and management of the water and sanitary systems..." The agreement further provides that "Crosland shall not be required to fund any operating or other deficits nor shall it be required to make any additional capital contributions."

Further, it is significant to note, notwithstanding the creation of the joint venture partnership, that it appears that Mid South continues to face the very same potential income tax liability of $534,000, before consideration of any penalty or interest that might be due, arising from its having received taxable CIAC as discussed hereinabove.

Surry Water Company, Inc.

On April 21, 1992, Surry filed an application for a franchise to provide utility services within Bishops Ridge Subdivision. In an attempt to assess the financial fitness of Surry, the Company's annual reports on file with the Commission were examined for the calendar years 1987 through 1991. In addition to other deficiencies, that examination revealed that the Company's 1991 annual report was incomplete and that a revised report needed to be filed with the Commission.

A revised 1991 annual report was subsequently provided by Surry. After having examined that report and other information in its files, the Commission denied the Company's application for a franchise to serve Bishops Ridge. In its Order Denying Franchise the Commission presented the following comments:

> "As presented on the December 31, 1991 balance sheet contained in Surry's revised 1991 annual report, the total proprietary capital of the Company is a negative $500,501 (emphasis added in the original). This amount consists of common stock of $500, unappropriated earned surplus of $21,817, and $522,818 of treasury stock. In revising its 1991 annual report, it appears that the Company made an entry to its books to record a long-term note payable to the original owner of Surry for the purchase of the Company with a concomitant entry to record a like amount of treasury stock.
>
> "The Company's recording of the aforementioned long-term debt and the attendant treasury stock on its books brings clearly into focus for the first time what appears to be the truly tenuous nature of Surry's financial well being. As reflected in the official files of the Commission, the Webers agreed to pay Ms. Lovill, then the sole shareholder of Surry, in excess of $500,000 for 100 percent of the outstanding common stock of the Company. The information and data on file with the Commission do not reflect the total book value of the Company's common stock or the economic value of the firm on or about the time of its acquisition by the Webers in October 1989. However,

it does appear that the total book value of the Company's common stock at December 31, 1991, and the current economic value of this regulated public utility as a going concern pale in comparison to the purchase price paid by the Webers for its acquisition.

"The economic earning power of Surry was not and will not be enhanced as a result of the Webers having purchased its outstanding common stock for a sum in excess of $500,000. And, most assuredly, the Company's economic and financial well being was not and will not be enhanced as a result of its having incurred a liability in the form of a note payable in excess of $500,000, which apparently was issued or assumed as consideration in exchange for the treasury stock now reflected on its revised 1991 balance sheet.

"Surry's revised 1991 annual report recently provided to the Commission shows that its operating income for that calendar year was $42,138 and that overall the Company experienced a net loss of $29,838. The preponderance of the net loss appears to arise as a result of interest payments of $50,437 largely due on a note(s) payable to Ms. Lovill, the individual from whom the Webers purchased Surry.

"Consistent with North Carolina law and the ratemaking practices of this Commission, interest payments on funds used to purchase treasury stock, clearly in this instance, are not reasonable costs properly recoverable from the customers of this public utility. Since Surry will not be permitted to recover such costs from its customers and since the payments of interest and principal associated with these notes will have a significantly adverse effect on Surry's cash flow and/or its overall profitability, it now appears that Surry's financial position is such that the Commission would be remiss if it were to allow Surry to acquire an additional public utility franchise at this time.

"In reaching this decision, the Commission has been mindful of the fact that, as reported in its 1991 revised annual report, contributions in aid of construction (CIAC) of $621,936 received by Surry exceed the Company's total investment in net utility plant (utility plant less accumulated depreciation and amortization) of $604,932. Further, it is noted that, in reaching this decision, the Commission has not been unmindful of the fact that Surry's total assets and other debits of $666,597 are financed by an exceedingly limited amount of equity capital; i.e., $22,317. This sum assumes that other long-term debt (i.e., the note(s) payable to Ms. Lovill) and other sources of funding were used to finance the acquisition of the treasury stock.

"The Commission is cognizant of the fact that Surry's rates are set on the basis of an operating-ratio methodology as opposed to the rate base methodology. However, such a consideration does not diminish the significance of the fact that more than 100 percent of the Company's existing investment in net utility plant has been acquired or recovered through CIAC. This fact serves to highlight the propriety of excluding from recovery through the ratemaking process interest expense of any kind associated with Surry's net utility plant or its treasury stock.

"Finally, the Commission notes that it takes no comfort from the fact that Surry may have unencumbered assets which might be acceptable as security in raising additional funds for non-utility purposes, such as interest and principal payments to Ms. Lovill. Discomfort arises because as previously explained, under the ratemaking practices of this Commission, revenues collected under rates authorized for Surry would not provide for the payment of said interest, for the repayment of said principal or for recovery of any other non-utility cost. Such ratemaking treatment is appropriate because the costs of these assets or the assets themselves have been previously recovered or acquired as CIAC; for the Commission to do otherwise would be entirely inappropriate from the standpoint of fairness and equity, if not unlawful.

"The ultimate economic consequences of an entity's inability to meet interest and principal payments on encumbered assets are well known and need not be repeated here. Suffice it to say that it is the Commission's duty to insure that public utility assets needed in the provision of public utility services continue to be available for said purposes. And, the Commission will continue to discharge this responsibility with diligent care.

"All of the foregoing matters and concerns have been carefully considered by the Commission in reaching its decision herein. Due to the absence of a showing of Surry's financial fitness, the instant application for a certificate of public convenience and necessity to furnish water utility service in Bishops Ridge Subdivision in Forsyth County is denied. However, the Commission will consider without prejudice any future request to transfer this system to a qualified entity which can demonstrate operational and financial fitness, including a newly created entity organized by the equity investors of Surry if operated on a "stand-alone basis."

"The Commission has reached the foregoing decision without having afforded Surry an opportunity to be heard on the issues and concerns set forth herein. Therefore, the Commission hereby advises Surry that should it file a motion requesting a hearing on this matter on or before the expiration of 10 days from the issuance date of this Order such a request will be granted. The aforementioned issues and concerns are to be fully addressed by Surry at the hearing, should such a hearing be held. Further, should this matter be set for hearing, it is hereby requested that the Public Staff investigate the issues and concerns as identified herein, as well as any other matter(s) the Public Staff may consider appropriate, and present its findings to the Commission during the hearing held in this regard, if any."

Surry did not request a hearing as a result of the Commission's having denied its request for a franchise to serve the Bishops Ridge Subdivision.

However, as suggested by the Commission in its Order denying the subject franchise, the Webers did form a new corporate entity; i.e., Forsyth, which filed an application for a franchise to provide public utility services within the Bishops Ridge Subdivision.

Forsyth Water Systems, Inc.

As previously stated, a hearing was held on Forsyth's application for a franchise to serve the Bishops Ridge Subdivision on February 17, 1993. Also as previously stated, the preponderance of the direct testimony presented by Company witness Perkerson, the only witness in this proceeding, pertained to the financial viability of Surry Water Company, Inc.

During her direct testimony, witness Perkerson again revised Surry's 1991 annual report. The revisions were extensive. The treasury stock of $522,818 and the note payable to Ms. Lovill in excess of $500,000, which are discussed hereinabove (see excerpt from the Commission's Order denying Surry's application for a franchise to serve Bishops Ridge), were removed from the balance sheet.

By making several other accounting adjustments to remove interest expense associated with the aforementioned note as an obligation of the utility, Surry was able to create income and retained earnings. These earnings, however, are directly related to an accounts receivable from Carroll and Mary Weber which was entered on Mid South's books as one of the second set of revisions. While the accounting adjustments dramatically improve Surry's financial posture, they had no effect on the overall net worth of the Webers. Simply put, the effect of the accounting adjustments was to merely shift a liability (i.e., the note to Ms. Lovill) and its attendant interest costs from Surry to the Webers.

At the hearing on this matter, certain additional information was requested by the Commission. Such information was filed on April 8, 1993. Included in that filing was the following financial information which was filed under a seal of confidentiality:

(1) Exhibit No. 9 - A one page listing of the notes of Carroll and Mary Weber and of Mid South Water Systems, Inc.,

(2) Exhibit No. 10 - A two page personal financial statement of Carroll and Mary Weber dated December 31, 1992, with two attachments,

(3) Exhibit No. 11 - A copy of a Dun & Bradstreet report on Mid South Water Systems, Inc., dated March 24, 1993, and

(4) Exhibit No. 12 - A copy of the financial statement filed with then NCNB to secure a loan in the amount of $1,600,000 dated December 31, 1988.

Exhibit No. 9
(Notes of Carroll and Mary Weber and of Mid South Water Systems, Inc.)

Exhibit No. 9 is undated. However, it is assumed that this listing of notes is current as of the date of filing (i.e., April 8, 1993) and that it is all inclusive. Of the original total amount of the notes, 67 percent of such amount remains outstanding. Of the amount outstanding, 92 percent appears to be secured by the pledging of public utility assets. Neither the Webers nor Mid South sought or received Commission approval for the pledging of such assets.

Exhibit No. 10
(Personal Financial Statement
of Carroll and Mary Weber, Dated December 31, 1992)

This statement is essentially a balance sheet for the Webers at December 31, 1992. This balance sheet reflects very substantial net worth both in a relative, i.e., relative to debt or total capital, and in an absolute sense. However, such net worth is derived to an exceedingly large extent by virtue of the valuation methodology used in valuing the Webers' public utility investments.

Considering the evidence contained in the record of this proceeding, including the records of proceedings for which the Commission has herein taken judicial notice, and considering the "going concern" concept as appplied to regulated public utilities, the Commission cannot and does not accept as reasonable the values that have been placed on the Webers' public utility investments as reflected in the subject balance sheet. The reasons for the Commission's having reached this conclusion are discussed subsequently.

Exhibit No. 11
(Dun & Bradstreet Report
on Mid South Water Systems, Inc., Dated March 24, 1993)

As indicated the Dun & Bradstreet Report is on Mid South. The Company advises that Dun and Bradstreet does not provide reports on individuals. Therefore, no report is available on Carroll Weber.

This report shows that Mid South's net worth is approximately two percent of the value reported as Mid South's net worth in Exhibit No. 10 and approximately one percent of the value reported as Mid South's net worth in Exhibit No. 12, assuming this exhibit reflects book net worth. The Commission is not unmindful of the fact that the net worth presented in Exhibit No. 10 was as of December 31, 1992, whereas the net worth presented in Exhibit No. 11 was as of March 24, 1993. As indicated hereinabove and hereinbelow, the net worth presented in Exhibit No. 12 was as of December 31, 1988.

A note reflected on the Dun & Bradstreet report tends to indicate that the Company's accounting manager was unwilling to offer any information or otherwise verify the information contained in that report.

Exhibit No. 12
(Financial Statement, Dated December 31, 1988,
Provided to NCNB to Obtain Loan in the Amount of $1,600,000)

This exhibit, which is composed of a balance sheet at December 31, 1988, for Carroll and Mary Weber and two supplementary schedules, like Exhibit No. 10, reflects a very substantial net worth both in a relative and in an absolute sense. Moreover, the net worth reflected in Exhibit No. 12 is substantially greater than the net worth reflected in Exhibit No. 10. However, as with Exhibit No. 10, such net worth is derived to an exceedingly large extent by virtue of the valuation methodology used in valuing the Webers' public utility investments.

For the same reasons as stated herein by the Commission for its lack of acceptance of the values placed on certain assets in Exhibit No. 10, the Commission cannot and does not accept as reasonable the values that have been placed on the Webers' public utility investments as reflected in Exhibit No. 12.

The Financial Significance of Exhibit Nos. 9, 10, 11, and 12

Regarding the overall financial health of the Webers, including their public utility and other holdings, it is very difficult to draw any meaningful conclusions from the foregoing exhibits with any degree of confidence, with one exception. It is clear from the standpoint of a going concern that the Webers' net worth as presented in both Exhibit No. 10 and Exhibit No. 12 is grossly overstated.

Based on the latest annual report on file with the Commission, of which the Commission has heretofore taken judicial notice, the Webers, at December 31, 1992, appear to be reporting CIAC as common equity capital. Such reporting is totally misleading and entirely inappropriate from the standpoint of a regulated going concern.

One cannot determine from the information provided why the Webers' reported investment in Mid South declined by 48 percent between December 1988 and December 1992. However, it does appear that the Webers in their December 1988 report are treating CIAC as common equity capital, which, as previously stated, is entirely inappropriate.

Mid South's net worth at March 24, 1993, as presented by Exhibit No. 11, the Dun & Bradstreet report, is eminently more realistic and reasonable than are the levels of net worth presented in Exhibit Nos. 10 and 12. As previously stated, such net worth is approximately two percent of Mid South's net worth as reflected in Exhibit No. 10 and it is approximately one percent of the Company's net worth as presented in Exhibit No. 12.

Other Considerations Regarding Forsyth Water Systems, Inc.

During the Forsyth hearing, witness Perkerson testified that the Webers planned to give Mr. Lovill, the owner of the Bishops Ridge system, a note or notes in an amount of $31,150 as consideration for the purchase of the system. Capital invested by the Webers in Forsyth will appear on Forsyth's books and in its financial statements as common equity capital. Witness Perkerson also testified that the Company plans to post a $13,600 bond in order to comply with the Commission's bonding requirements. It is also significant to consider that, as previously stated, Forsyth plans to employ Surry as an outside contractor to provide many of the services that will be required in operating the Bishops Ridge System.

Witness Perkerson further testified that seven customers are now receiving service within Bishops Ridge. That service is now being provided cost free. In terms of recovering current monthly operating costs of $145, witness Perkerson testified that by serving two additional customers, i.e., a total of nine customers, revenues would slightly exceed operating expenses, assuming necessary operating services are provided by Surry personnel. That level of revenue recovery is based on the average monthly usage of the seven existing customers. The average monthly bill under the Company's proposed rates would be in the range of $18 per month according to witness Perkerson. The total number of customers ultimately to be served within Bishops Ridge is approximately 100.

Conclusion

On a stand-alone basis, one might conclude that Forsyth was both operationally and financially fit to provide water utility service within the Bishops Ridge Subdivision. However, in this instance, because of the commonality of ownership of Forsyth, Surry, and Mid South, the Commission would be remiss if it did not examine and consider certain facts and circumstances lying beyond Forsyth's corporate veil.

In certain Mid South and Surry dockets, of which the Commission has herein taken judicial notice, it has been determined that these companies had not carried the burden of proof so as to show that they were financially fit for the purpose of providing water and/or sewer services with respect to various public utility systems. The bases of the Commission's conclusions as to the absence of a showing of financial fitness in those instances are set forth heretofore and need not be repeated here. At this juncture, suffice it to say that this Commission continues to have grave concerns regarding their financial viability. Both companies appear to be significantly under-capitalized from the standpoint of equity capital and their ability to maintain adequate cash flow is at best unclear.

With respect to Forsyth's proposed financial structure, on the surface it might appear to be strong. For example, the Company states that its acquisition of the Bishops Ridge system will be 100 percent equity financed. At the present time, it appears that the Company's investment in Bishops Ridge would represent nearly all of its assets. However, as indicated above, witness Perkerson testified that the Webers planned to give the owner of the Bishops Ridge system a note or notes as consideration for the purchase of the system. Thus, it is entirely reasonable to conclude that the preponderance of the Webers' investment in Forsyth will be 100 percent debt financed. Thus, based upon the foregoing, the Commission can only conclude that the financial fitness of Forsyth is to a vast extent a function of the financial fitness of the Webers.

In an attempt to assess the financial standing of the Webers, the Commission has carefully reviewed and considered the information and data contained in Exhibit Nos. 9 through 12 as described and discussed hereinabove, as well as all other evidence of record. In view of the Commission's earlier findings with respect to Mid South and Surry, the fact that the Webers' investment in Forsyth would be in substance 100 percent debt financed, and the fact that the Commission cannot determine the overall financial fitness of the Webers from the information provided, it must be, and hereby is, concluded that Forsyth has not carried the burden of proof as to its financial fitness to provide water utility service in the Bishops Ridge Subdivision.

IT IS, THEREFORE, ORDERED that Forsyth's application for a certificate of public convenience and necessity to provide water utility service in Bishops Ridge Subdivision, Forsyth County, North Carolina is hereby denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of May 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-848, SUB 15
DOCKET NO. W-848, SUB 16

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. W-848, Sub 15

In the Matter of Piney Mountain Homeowners Association, Inc., Complainant v. North State Utilities, Inc., Respondent Docket No. W-848, Sub 16 In the Matter of North State Utilities, Inc., Petition to Abandon All of Its Sewer Systems in North Carolina	RECOMMENDED ORDER APPOINTING EMERGENCY OPERATORS AND APPROVING INTERIM RATES

HEARD: July 26, 1993, at 7:00 p.m., Commission Hearing Room, 430 North Salisbury Street, Raleigh, North Carolina

August 12, 1993, at 7:30 p.m., Charlotte-Mecklenburg Government Center, Room 270, 600 E. Fourth Street, Charlotte, North Carolina

BEFORE: Wilson B. Partin, Jr., Hearing Examiner

APPEARANCES:

For North State Utilities:

James F. Jordan, Jordan Law Offices, 5509 Creedmoor Road, Suite 200, Raleigh, North Carolina 27612

For Piney Mountain Homeowners Association:

Nancy Essex, Poyner & Spruill, Post Office Box 10096, Raleigh, North Carolina 27607

For the Using and Consuming Public:

Robert B. Cauthen, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

For Carpenter Pond Corporation:

Martha K. Walston, McMillan, Kimzey & Smith, Post Office Box 150, Raleigh, North Carolina 27602

PARTIN, HEARING EXAMINER: Docket No. W-848, Sub 15 was instituted on May 20, 1993, when the Piney Mountain Homeowners Association filed a complaint in this docket against North State Utilities, Inc.

On June 7, 1993, North State filed an answer to the complaint.

On June 9, 1993, the Commission issued an order serving the answer upon the Homeowners Association, who subsequently advised the Commission that a hearing on its complaint should be set as soon as possible. The Homeowners Association also requested that the Commission appoint an emergency operator pursuant to G.S. 62-118 as soon as possible.

On June 30, 1993, North State Utilities filed Petition to Abandon or for Alternate Relief in Docket No. W-848, Sub 16. The Petition set forth all of these service areas of North State and the number of customers served in each service area. In support of its Petition, the Company alleged that its existing revenues are insufficient to provide for service on an ongoing basis.

On July 14, 1993, the Commission issued an Order scheduling hearing on the complaint on the Piney Mountain Homeowners' Association and the Petition to Abandon of North State Utilities. Hearings were scheduled in Raleigh on July 26, 1993, and in Charlotte on August 12, 1993. North State was required to give notice of the hearings to all of its customers.

The Order of July 14, 1993, also appointed Harrco Utility Corporation as emergency operator of the Piney Mountain sewer system pursuant to G.S. 62-116. The hearings were to consider the appointment of an emergency operator pursuant to G.S. 62-118(b) for all of the Company's sewer systems including Piney Mountain, and the imposition of assessments for capital improvements.

The Order of July 14, 1993, also required North State to continue to provide sewer service to all of its customers in all of its service areas pending hearing and decision on its Petition to Abandon.

These dockets came on for hearing as scheduled in Raleigh and in Charlotte. A large number of customers appeared at the Raleigh hearing and numerous witnesses presented testimony, including representatives of the Wake, Durham, and Orange Counties' Health Departments. Stanley I. Hofmeister, a shareholder and a vice-president of North State Utilities, offered testimony in support of the Petition to Abandon.

FINDINGS OF FACT

1. North State Utilities, Inc., is a public utility regulated by the Commission and has been granted certificates of public convenience and necessity to provide sewer utility service in the following service areas: Manchester, Monticello, Woods of Ashbury, Sutton Estates, Banbury Woods, Holly Brook, and Saddleridge Subdivisions in Wake County; Piney Mountain Subdivision in Orange County; Wexford Subdivision in Durham County; and Oakcroft Subdivision in Mecklenburg County.

2. North State serves approximately 270 customers in its service areas at a rate of $18.00 per customer per month for service in arrears. The $18.00 monthly rate has remained unchanged since the Company first received a franchise from the Commission in 1986.

3. North State has petitioned the Commission for authority to abandon its sewer service pursuant to G. S. 62-118 or, in the alternative, to reduce its service to all of its customers. The Company alleged that its revenues are insufficient to provide service to its customers on an on-going basis. In its Petition to Abandon, North State consented to the appointment of an emergency operator in all of its service areas.

4. There are serious deficiencies in almost all of the North State sewer systems. These systems do not comply with the applicable standards and regulations of the Health Departments of Wake, Durham, Orange, and Mecklenburg Counties and the Division of Environmental Health (DEH). Homeowners in the subdivisions who are customers of the Company face the prospect of loss of sewer service and substantial financial loss due to these deficiencies, unless the deficiencies are corrected.

5. Wexford Subdivision is in Durham County. The system does not at present have a permit from the Durham County Health Department. The sewer system in Wexford needs what has been described as "fairly minor repairs", including the replacement of all of the indicator lamps in the electrical control panel and the repair of two out-of-service subfields.

6. Monticello Subdivision is in Wake County, and the system was originally permitted in 1986. The present permit expires in 1996. The system has rather extensive malfunctioning as indicated by the surfacing of effluent over the drain fields. The cost of correcting this malfunction has been estimated in the range of $20,000 to $40,000. The system needs a substantial amount of vegetative maintenance as well as relandscaping to eliminate low and settled areas.

7. Manchester Subdivision is in Wake County. There is currently a malfunction on three subfields. Although North State has undertaken extensive work to eliminate some of the problems, problems still remain of a undetermined origin. There needs to be vegetative maintenance and relandscaping.

8. Sutton Estates Subdivision is in Wake County. A recent inspection revealed that there was surfacing effluent on two subfields in that system. The system needs vegetative maintenance and some relandscaping work to eliminate low areas that are ponding water. The system also needs a normal maintenance schedule for checking and pumping individual septic tanks.

9. Banbury Woods in Wake County has basically the same problems as Sutton Estates Subdivision.

10. Holly Brook Subdivision in Wake County has basically the same problems as Sutton Estates and Banbury Woods. There was one subfield malfunctioning at the last inspection by the Wake County Health Department. A new phase of Holly Brook has not yet been authorized for operation.

11. Woods of Ashbury Subdivision in Wake County has no observable malfunction. The needs in this subdivision are basically related to establishing

normal maintenance procedures. Additionally there is need for relandscaping to eliminate low and settled areas within the system, as well as a means of monitoring waste water flow.

12. Saddleridge Subdivision in Wake County has no observable indication of malfunctioning. As in Woods of Ashbury, the system basically needs normal maintenance procedures and procedures for dealing with individual septic tanks.

13. The Piney Mountain Subdivision in Orange County needs extensive work. The Orange County Health Department has placed an expiration date of July 1, 1996 on the permit; however, the permit was to expire on August 4, 1993, if the sewer system did not meet certain conditions. If the conditions are not eventually met, the Piney Mountain system could face the possibility of being shut down by the Health Department. There is not an alternative system in place at Piney Mountain for sewage disposal. Attempts by the Orange County Health Department to gain compliance from North State were not successful.

14. Oakcroft Subdivision in Mecklenburg County is not yet permitted by the Mecklenburg County Health Department. The system needs regular maintenance procedures, and the vegetation needs to be mowed.

15. Harrco Utility Corporation of Raleigh has agreed to become emergency operator for all of North State's sewer systems in Wake, Durham, and Orange Counties. Harrco Utility Corporation is a public utility regulated by this Commission and has experience in the type of sewer system to be found in the North State service areas. Harrco has made a limited inspection of all of the sewer systems in these three counties and has found "the same state of disrepair that most of the regulatory agencies has testified to."

16. Based upon Harrco's investigations of these systems, Harrco asked that it be given a rate of $86.50 per month per connection as an interim rate for the first six months of operation, pursuant to the conditions set forth in Ordering Paragraph 8, below.

17. Harrco will also prepare a list of the capital improvements that are needed in each system in order to bring these systems into compliance with the rules and regulations of the Division of Environmental Health and the Wake, Durham, and Orange Counties Health Departments.

18. At the present time Harrco is serving as emergency operator in Piney Mountain Subdivision pursuant to G. S. 62-116, and was appointed emergency operator under G. S. 62-116 for all of the Wake, Durham, and Orange County systems from August 27, 1993, until midnight August 31, 1993.

19. Harrco is qualified to become emergency operator of the Wake, Durham, and Orange Counties sewer systems of North State at a provisional interim rate of $86.50 per connection per month.

20. Tri-County Wastewater Management of Monroe has agreed to become the emergency operator for the sewer utility system in Oakcroft Subdivision, Mecklenburg County, at a provisional interim rate of $85.00 per connection per month, under the same conditions as Harrco. Tri-County is qualified to serve as emergency operator of the Oakcroft Subdivision.

21. Heater Utilities and Mid South Water Systems have agreed to provide billing and collection services for the emergency operators in those subdivisions in which they provide water utility services. Heater and Mid South are authorized to charge $2.00 per connection per month for these services, which will include the disconnection of water utility service to any person who fails to pay the sewer charges of the emergency operators.

22. The North Carolina Division of Environmental Health, and the Wake, Durham, and Orange Counties Health Departments have reached an agreement with Harrco concerning the extent of Harrco's liability in assuming the duties of emergency operator. The provisions of that agreement are attached to this Order as Appendix D and are incorporated into this Order as if fully set out.

23. That under the circumstances of this case, the rate proposed by the emergency operators of $86.50 per month per connection ($85.00 in the case of Tri-County) is reasonable and necessary in order to prevent the total or partial loss of sewer service to the affected subdivisions of North State.

24. North State has filed $20,000 in bonds with the Utilities Commission pursuant to G. S. 62-110.3. Pursuant to this statute, these bonds are hereby declared forfeited. (North State consented to the forfeiture of these bonds during the hearings in these dockets.) The proceeds of the bonds will be subject to distribution by the Commission in subsequent orders.

25. The emergency operators shall investigate the need for any capital improvements in the service areas under their operation which may require the imposition of an assessment. The emergency operators shall obtain approval of the Commission of any assessments prior to making such improvements. Customers of the Company are to be notified of any proposed assessment and shall be afforded an opportunity for a hearing.

CONCLUSIONS

I

There is an emergency in all of the sewer utility service areas of North State which requires the appointment of emergency operators pursuant to G. S. 62-118(b). An emergency is defined as the imminent danger of losing adequate sewer utility service or the actual loss thereof.

All of the parties in this proceeding, as well as the various health agencies that regulate North State, agree that emergency operators should be appointed for the North State systems. The evidence is also uncontradicted that almost all of North State's sewer systems have serious deficiencies, in that they do not comply with the applicable rules and regulations of the health agencies which are responsible for regulating them. Mr. Hofmeister of North State testified that the Company is financially unable to make the improvements so as to bring the systems into compliance with applicable law and regulations. Nor does North State have the expertise to bring the systems into compliance.

II

Harrco Utility Corporation and Tri-County Waste Management are fully qualified to perform the duties of emergency operator pursuant to G. S. 62-118(b).

III

Irreparable injury, loss, and damage would result to the customers of the sewer systems of North State if the appointment of the emergency operators would be denied, in that the health, safety, and welfare of the customers would be continuously threatened by the actual and potential loss of safe, adequate, and reliable sewer utility service. Moreover, the customers of the sewer systems would suffer severe financial loss in the event that the sewer systems were declared nonoperable by the regulatory health agencies. There is no other source of sewer service available to the customers of North State.

IV

Under the circumstances of this proceeding, the rate requested by the emergency operators in the amount of $86.50 per connection per month ($85.00 in the case of Tri-County) should be approved as the rate for the emergency operators. The appointment as emergency operator is a voluntary one, and no company should be required to become emergency operator if it would mean financial loss to it. Harrco and Tri-County have determined, after initial investigation of the sewer systems, that rates of $86.50 and $85.00 a month respectively for six months would compensate them for any possible expenses arising out of their emergency operation of the sewer systems. The Commission points out that these rates are interim provisional rates, which are subject to review by the Commission at the end of six months from the appointment of the emergency operators, pursuant to Ordering Paragraph 8 below.

V

The Petition of North State to abandon its sewer franchises should be denied. North State has not carried the burden of proof set by G. S. 62-118 of showing that the public convenience and necessity is no longer served in its service areas or that there is no reasonable possibility of realizing sufficient revenues to meet the expenses of the utility or to make capital improvements. Moreover, despite the appointment of the emergency operators herein, North State retains title and ownership of the sewer systems. The necessary sewer permits are in the name of North State. It is important that North State remain a viable corporation holding a franchise from this Commission in order that the work of emergency operators may take place without impairment.

IT IS, THEREFORE, ORDERED as follows:

1. That the Petition of North State Utilities, Inc., for permission to abandon its sewer franchises is denied.

2. That Tri-County Wastewater Management, 712 South Hayne Street, Monroe, North Carolina, is hereby appointed emergency operator for the sewer utility system serving Oakcroft Subdivision, Mecklenburg County, North Carolina, effective as of September 1, 1993, at a provisional interim rate of $85.00 per connection per month for service in advance.

3. That Harrco Utility Corporation, 8601 Barefoot Industrial Road, Raleigh, North Carolina, is hereby appointed emergency operator for the sewer utility systems serving Manchester, Monticello, Woods of Ashbury, Sutton Estates, Banbury Woods, Holly Brook, and Saddle Ridge Subdivisions in Wake County; Piney

Mountain Subdivision in Orange County; and Wexford Subdivision in Durham County, North Carolina, effective as of September 1, 1993, at a provisional interim rate of $86.50 per connection per month for service in advance.

4. That North State Utilities, Inc., its officers, directors, and shareholders, are hereby ordered to offer all reasonable assistance to the emergency operators named in this Order. North State Utilities, Inc., its officers, directors, and shareholders, shall not by any act or omission unreasonably prevent or impair the continued existence of North State Utilities, Inc., as a North Carolina corporation in good standing. North State Utilities, Inc., is directed to accept or transfer any utility property, the acceptance or transfer of which is reasonably necessary to the continued provision of sewer service in any of North State's service areas, including but not limited to the property in the name of Carpenter Pond Development Corporation located in Wexford Subdivision, Durham County. North State shall not dispose or divest itself of any utility property, real or personal, without the prior written consent of the Commission.

5. That Tri-County Wastewater Management and Harrco Utility Corporation (collectively "the emergency operators") are authorized to obtain billing and collection services from Heater Utilities and Mid South Water Systems, Inc., where such services are available. Heater Utilities, Inc., and Mid South Water Systems, Inc., are authorized to provide billing and collection services to the emergency operators in those subdivisions in which they provide water utility service. Heater and Mid South are authorized to charge $2.00 per connection per month for these services, this amount to be retained from the gross proceeds, and to disconnect water utility service for failure of any customer to pay sewer charges.

6. That sewer bills in the service areas through the month of August 1993 shall remain due and payable to North State. The service of any customer remaining in arrears to North State is subject to discontinuance for failure of the customer to pay past due amounts. North State shall be responsible for collecting these bills but may request the assistance of the Commission in discontinuing service.

7. That the emergency operators shall maintain full records of receipts and expenses by subdivision and shall file with the Commission and Public Staff, by the end of the subsequent month, a summary report by subdivision monthly.

8. That at a date and time to be established, approximately six months after the date of this Order, hearings will be held to evaluate the revenues and expenses of the emergency operators and to adjust the approved provisional interim rates as necessary. If it is determined that the rates approved herein exceed the rates which would have been necessary to cover the emergency operators' reasonable and prudent operating expenses plus a reasonable return in any subdivision, the difference shall be either refunded or applied to necessary capital improvements as appears appropriate, and new rates shall be approved for service rendered thereafter. If it is determined that the rates approved herein are less than the rates which would have been necessary to cover the emergency operator's reasonable and prudent operating expenses and provide a reasonable return, the difference shall be collected through a surcharge, and new rates shall be approved for service rendered thereafter.

9. That, within 60 days after the date of this Order, the emergency operators shall advise the Commission in writing of the need for any capital improvements requiring the imposition of an assessment under G.S. 62-118(c) and shall obtain approval of an assessment prior to making such improvements; provided, however, that the emergency operators may make such capital improvements as may be necessary to prevent the loss of adequate sewer service pending request for and approval of an assessment.

10. That the bonds posted by North State Utilities pursuant to G.S. 62-110.3 are hereby declared forfeited; the proceeds of the bonds shall be distributed by subsequent Orders of the Commission.

11. That the emergency operators shall assume control of the operations of the sewer systems on and after September 1, 1993.

12. That, subject to Ordering Paragraph 9 above, the emergency operators, effective on and after the date of this Order, shall have charge of the daily operation of the sewer systems included in this Order, and their duties and responsibilities shall include, among others, the following:

(i) Regular inspections and testing of the sewer systems;

(ii) Billing of all customers and collection of bills;

(iii) Routine and emergency maintenance and repair;

(iv) System renovations and additions necessary to maintain adequate sewer service; and

(v) Monthly accounting to the Utilities Commission and the Public Staff of all rates collected, expenses incurred, checks written, and all monies spent.

13. That the emergency operators may contract with any person or corporation to carry out any of the duties necessary for operation, repair, and expansion of the sewer systems, but the emergency operators alone shall have the ultimate responsibility to see that such duties are carried out.

14. That the emergency operators, in the performance of their duties, shall be free to seek assistance from customers of the sewer system, plumbers, engineers, attorneys, and other persons as may be necessary for the performance of their duties and responsibilities.

15. That the emergency operators shall, when it becomes necessary in the performance of their duties, seek the assistance of the Division of Environmental Health, the North Carolina Utilities Commission, the Public Staff of the NCUC, and the Wake, Durham, Orange, and Mecklenburg Counties Health Departments.

16. That the emergency operators shall collect from the customers of the sewer systems such rates and assessments as may be approved by the NCUC and shall be fully authorized to bill and collect said rates and assessments and to disburse such of these funds as may be necessary to provide safe, reliable, and

adequate sewer utility service to the customers. Any customer who fails to pay the bills(s) authorized by this paragraph shall be disconnected by the emergency operators as provided by the orders, rules, and regulations of the NCUC.

17. That the emergency operators shall be entitled to all available records relating to the sewer systems, and these records shall include, but not be limited to, a list of customer names, addresses, and billing records. On or before September 1, 1993, North State Utilities, Inc., shall provide to the emergency operators the records identified in Appendix A to this Order.

18. That the emergency operators shall keep records of all monies collected through the rates and assessments and all monies expended in the operation of the sewer systems. In order to protect the customers' investments in the sewer systems in the event the sewer systems should be sold or revert to North State, the emergency operators are required to keep a separate record of all monies and assessments collected from the customers and expended on improving and upgrading the sewer systems, including, but not limited to, the installation of new plant, meters, wells, rebuilt equipment, and the cost of labor associated with these improvements whether performed by the emergency operators or a contractor hired by the emergency operators.

19. That the emergency operators shall pay only those liabilities incurred by the emergency operators on and after the date of the appointment of the emergency operators. These liabilities shall be defined as the liabilities arising from the emergency operators' operation of the Respondent's sewer systems pursuant to this Order. North State shall deliver to the emergency operators a list of all materials, supplies, and inventories on the properties associated with the sewer systems. The emergency operators shall account for all materials, supplies, and inventories of North State Utilities, Inc., which are used by the emergency operators in the operation of the sewer systems. The disbursements by the emergency operators shall be made from the separate account set up by the emergency operators; the emergency operators shall account for any funds advanced by them for the operations.

20. That North State Utilities, Inc., its officers, agents, servants, and employees, shall not

(a) Interfere with the emergency operators' operation of the sewer utility plants, including the pumps, wells, well lots, easements, rights-of-way, treatment facilities, mains, distribution lines, storage or holding facilities, meters, filters, or taps;

(b) Receive or attempt to collect any sewer bill payments or monies for sewer service provided by the emergency operators;

(c) Alter, impair, or remove any of the sewer utility plants.

21. That North State shall petition the Commission for approval if it wishes to resume the operation of the sewer systems as a franchised public utility under the jurisdiction of the NCUC or to sell or otherwise dispose of the sewer systems according to law. Notice of the Petition shall also be given to the Division of Environmental Health and the Mecklenburg, Wake, Durham, and Orange Counties Health Departments at the same time the Petition is filed with the Commission. The Commission shall schedule a hearing on such Petition of

North State and shall notify all parties to this proceeding, the customers of the sewer systems, and DEH and the Mecklenburg, Wake, Durham, and Orange Counties Health Departments. At said hearing North State shall have the burden of proof to satisfy the Commission that the relief sought in its Petition is justified by the public convenience and necessity and that North State or the transferee will operate said sewer systems in compliance with the rules and regulations of all state and county agencies, including the Commission and the Division of Environmental Health.

22. That the appointment of the emergency operators established by this Order shall continue until terminated by an Order of the Commission finding that the emergency has ended and that the emergency operators are no longer required pursuant to G.S. 62-118(b) to provide sewer public utility service to the customers of the said systems.

23. That the emergency operators may petition the Commission at any time to be discharged as emergency operators herein; and the emergency operators, prior to their discharge, shall provide an acceptable accounting to the NCUC of all monies collected and disbursed during their tenure as emergency operators, as well as the amounts due and owing the emergency operators at the time of their discharge for their services performed as emergency operators. An emergency operator filing a petition for discharge shall also mail a copy of said Petition to the Wake, Durham, and Orange County Health Departments, or the Mecklenburg Health Department if applicable, and the Division of Environmental Health.

24. That this docket shall remain open for further motions, reports, etc., of the parties, the emergency operators, the Mecklenburg, Wake, Durham, and Orange Counties Health Departments, the Division of Environmental Health, and for further Orders of the Commission.

25. That within five days after the date of this Order, Harrco shall mail or hand deliver the Notice to Customers attached to this Order as Appendix B; Tri-County shall mail or hand deliver the Notice attached as Appendix C.

26. That the Division of Environmental Health and the Health Departments of Wake, Durham, and Orange Counties shall be added to the mailing lists in these dockets in order to received this Order and future Orders of this Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

For Exhibit A and Appendix D see Official Copy of Order in Chief Clerk's Office.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-848, SUB 15
DOCKET NO. W-848, SUB 16

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. W-848, Sub 15

In the Matter of Piney Mountain Homeowners Association, Inc., Complainant v. North State Utilities, Inc., Respondent Docket No. W-848, Sub 16 In the Matter of North State Utilities, Inc., Petition to Abandon All of Its Sewer Systems in North Carolina	NOTICE TO THE CUSTOMERS OF NORTH STATE UTILITIES, INC., IN WAKE, DURHAM, AND ORANGE COUNTIES

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has appointed Harrco Utility Corporation of Raleigh as the emergency operator for all of the sewer utility systems of North State Utilities, Inc., in Wake, Durham, and Orange Counties. The appointment of Harrco as emergency operator is effective on and after September 1, 1993.

The service areas of North State affected by this appointment are as follows: Manchester, Monticello, Woods of Ashbury, Sutton Estates, Banbury Woods, Holly Brook, and Saddleridge Subdivisions in Wake County; Piney Mountain Subdivision in Orange County; and Wexford Subdivision in Durham County.

The appointment of Harrco as emergency operator is the result of formal proceedings before the Commission in July and August 1993, upon complaint of the Piney Mountain Homeowners Association, Inc. of Orange County and upon the Petition of North State Utilities, Inc., for permission to abandon all of its sewer systems in North Carolina.

Although the Commission has appointed Harrco as the emergency operator for the North State sewer systems in the three counties, the Commission also denied the Petition of North State Utilities for authority to abandon its sewer systems. The Commission specifically required North State to offer all reasonable assistance to the emergency operator and not to prevent or impair the continued existence of North State Utilities as a North Carolina corporation in good standing.

The Commission also approved a provisional interim rate for Harrco of $86.50 per connection per month for service in advance, beginning on and after September 1, 1993.

In its Order appointing Harrco as emergency operator, the Commission cited the financial problems of North State and its inability to provide adequate sewer service to its customers in compliance with State law and the rules and regulations of the County Health Departments in Orange, Durham, and Wake Counties. The Order also noted that North State lacked the technical expertise to correct the deficiencies in the sewer systems. The Order further noted that there were serious deficiencies in almost all of North State's sewer systems in the three counties, in that these systems do not comply with the applicable standards and regulations of the North Carolina Division of Environmental Health and the Health Departments of Wake, Durham, and Orange Counties. The Commission specifically noted that customers of the Company face the real prospect of loss of sewer service and substantial financial loss due to these deficiencies, unless the deficiencies are corrected.

The need for the appointment of Harrco as the emergency operator of the above-named systems was supported by the Public Staff of the North Carolina Utilities Commission, the Division of Environmental Health of the Department of Environmental, Health, and Natural Resources, and the Health Departments of Wake, Durham, and Orange Counties.

The Commission has found a provisional interim rate of $86.50 per month to be reasonable and appropriate. This rate is based on the best available current estimate of the cost of operation of these systems. The Commission's Order provides that approximately six months after September 1, 1993, hearings will be held to evaluate the revenues and expenses of Harrco in each service area, to adjust the interim rates as necessary, and to refund or surcharge if the interim rate proves to have been unreasonably excessive or inadequate.

The emergency operator has been authorized to bill for service in advance so as to minimize the operator's out-of-pocket expenses.

Harrco will also be responsible for determining, with the assistance of the County Health Departments, those improvements that need to be made to the sewer systems to bring them fully into compliance with State law. Harrco is also to prepare its best estimates of the costs of the capital improvements and to submit a list of the improvements and their estimated costs to the Commission. Upon receipt of this information, the Commission will schedule a hearing to present this information to all customers of the Company affected by the proposed improvements.

Harrco will assume full control of operations of the sewer systems on and after September 1, 1993, and will be responsible for operating the systems, billing of customers and the collection of bills, and making such system improvements as are required by law. Harrco will also provide monthly accounting to the Commission of all rates collected, expenses incurred, and all monies spent. North State is not to collect any bills for service rendered by the emergency operators on and after September 1, 1993, although North State is entitled to bill and collect for service provided through August 31, 1993.

The appointment of Harrco as emergency operator was made pursuant to North Carolina General Statutes 62-118, which provides for the appointment of an emergency operator in those systems which are in a state of emergency. An emergency is defined as the imminent loss or the actual loss of adequate water and sewer service.

Customers of the sewer system are requested by the Commission to fully cooperate with the emergency operator as it undertakes its responsibilities to bring all of the sewer systems into compliance with the North Carolina law and the rules and regulations of the Health Departments of Wake, Durham, and Orange Counties.

For further information concerning this Order, customers may call Wilson B. Partin, Jr., Deputy General Counsel, North Carolina Utilities Commission at 733-0836.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX C

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-848, SUB 15
DOCKET NO. W-848, SUB 16

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. W-848, Sub 15

In the Matter of
Piney Mountain Homeowners Association, Inc.,
Complainant

v.

North State Utilities, Inc.,
Respondent

Docket No. W-848, Sub 16

In the Matter of
North State Utilities, Inc., Petition to Abandon All of Its Sewer Systems in North Carolina

NOTICE TO THE CUSTOMERS OF NORTH STATE UTILITIES, INC., IN MECKLENBURG COUNTY

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has appointed Tri-County Wastewater Management of Monroe as the emergency operator for the sewer utility system of North State Utilities, Inc., in Mecklenburg County. The appointment of Tri-County as emergency operator is effective on and after September 1, 1993.

The service area of North State affected by this appointment is as follows: Oakcroft Subdivision.

The appointment of Tri-County as emergency operator is the result of formal proceedings before the Commission in July and August 1993, upon complaint of the Piney Mountain Homeowners Association, Inc. of Orange County and upon the Petition of North State Utilities, Inc., for permission to abandon all of its sewer systems in North Carolina.

Although the Commission has appointed Tri-County as the emergency operator for the North State sewer system in Mecklenburg County, the Commission also denied the Petition of North State Utilities for authority to abandon its sewer systems. The Commission specifically required North State to offer all reasonable assistance to the emergency operator and not to prevent or impair the continued existence of North State Utilities as a North Carolina corporation in good standing.

The Commission also approved a provisional interim rate for Tri-County of $85.00 per connection per month for service in advance, beginning on and after September 1, 1993.

In its Order appointing Tri-County as emergency operator, the Commission cited the financial problems of North State and its inability to provide adequate sewer service to its customers in compliance with State law and the rules and regulations of the County Health Departments in Mecklenburg, Orange, Durham, and Wake Counties. The Order also noted that North State lacked the technical expertise to correct the deficiencies in the sewer systems. The Order further noted that there were serious deficiencies in almost all of North State's sewer systems in the four counties, in that these systems do not comply with the applicable standards and regulations of the North Carolina Division of Environmental Health and the Health Departments of Mecklenburg, Wake, Durham, and Orange Counties. The Commission specifically noted that customers of the Company face the real prospect of loss of sewer service and substantial financial loss due to these deficiencies, unless the deficiencies are corrected.

The need for the appointment of Tri-County as the emergency operator of the Oak Croft system was supported by the Public Staff of the North Carolina Utilities Commission, the Division of Environmental Health of the Department of Environmental, Health, and Natural Resources, and the Health Department of Mecklenburg County.

The Commission has found a provisional interim rate of $85.00 per month to be reasonable and appropriate. This rate is based on the best available current estimate of the cost of operation of these systems. The Commission's Order provides that approximately six months after September 1, 1993, hearings will be held to evaluate the revenues and expenses of Tri-County in Oak Croft, to adjust the interim rates as necessary, and to refund or surcharge if the interim rate proves to have been unreasonably excessive or inadequate.

The emergency operator has been authorized to bill for service in advance so as to minimize the operator's out-of-pocket expenses.

Tri-County will also be responsible for determining, with the assistance of the Mecklenburg County Health Department, those improvements that need to be made to the sewer system to bring it fully into compliance with State law. Tri-County is also to prepare its best estimates of the costs of the capital improvements and to submit a list of the improvements and their estimated costs to the Commission. Upon receipt of this information, the Commission will schedule a hearing to present this information to customers of the Company affected by the proposed improvements.

Tri-County will assume full control of operations of the sewer system on and after September 1, 1993, and will be responsible for operating the system, billing of customers and the collection of bills, and making such system improvements as are required by law. Tri-County will also provide monthly accounting to the Commission of all rates collected, expenses incurred, and all monies spent. North State is not to collect any bills for service rendered by the emergency operator on and after September 1, 1993, although North State is entitled to bill and collect for service provided through August 31, 1993.

The appointment of Tri-County as emergency operator was made pursuant to North Carolina General Statutes 62-118, which provides for the appointment of an emergency operator in those sewer and water systems which are in a state of emergency. An emergency is defined as the imminent loss or the actual loss of adequate water and sewer service.

Customers of the sewer system are requested by the Commission to fully cooperate with the emergency operator as it undertakes its responsibilities to bring the sewer system into compliance with the North Carolina law and the rules and regulations of the Mecklenburg County Health Department.

For further information concerning this Order, customers may call Wilson B. Partin, Jr., Deputy General Counsel, North Carolina Utilities Commission at (919) 733-0836.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-200, SUB 25

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by LaGrange Waterworks Corporation, Post Office Box 40707, Fayetteville, North Carolina 28309, for Authority to Increase Rates for Water Utility Service in All Its Service Areas in Cumberland County, North Carolina	) ORDER APPROVING PARTIAL INCREASE IN RATES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, Salisbury Street, Raleigh, North Carolina, on August 6, 1993, at 9:30 a.m. and Hearing Room 3, Second Floor, Old Cumberland County Courthouse, 130 Gillespie Street, Fayetteville, North Carolina, on July 14, 1993, at 7:00 p.m.

BEFORE: Chairman John E. Thomas, Presiding, and Commissioners Charles H. Hughes and Allyson K. Duncan

APPEARANCES:

For the Applicant:

William E. Grantmyre, Attorney at Law, P.O. Drawer 4889, Cary, North Carolina 27519

For the Public Staff:

James D. Little, Staff Attorney, Public Staff, North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

BY THE COMMISSION: On February 22, 1993, LaGrange Waterworks Corporation (LaGrange) filed an application for a general rate increase. By Order issued on March 18, 1993, the Commission declared the application to be a general rate case, suspended the proposed rates, required public notice, and scheduled hearings.

Public notice was given to the customers as evidenced by the Certificate of Service filed by LaGrange.

On June 1, 1993, LaGrange prefiled the testimony of Hunter Chadwick, President, George Dennis, CPA, and Jerry Tweed.

On June 23, 1993, the Public Staff filed a motion for extension of time to file its testimony.

On June 23, 1993, LaGrange, by verbal motion through its attorney, requested an additional hearing to receive the testimony of the expert witnesses from the Company, Public Staff and other intervenors.

On July 7, 1993, the Public Staff filed the Notice of Affidavit and Affidavit of George T. Sessoms, Jr., Director, Financial Analyst, Economic Division, Public Staff.

By Order issued June 25, 1993, the Public Staff was granted an extension to prefile its testimony to and including July 9, 1993, and LaGrange was granted an extension to prefile its rebuttal testimony to and including July 23, 1993. This Order also scheduled an additional hearing for August 6, 1993, at the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, to receive the testimony of all expert witnesses. This Order further stated that the July 14, 1993, night hearing in Fayetteville, North Carolina, would be limited to the receiving of testimony of the customers.

On July 9, 1993, the Public Staff prefiled the testimony of Henry Mbonu, Staff Accountant, Accounting Division, and O. Bruce Vaughan, Utilities Engineer, Water Division.

The issue of gain on sale from LaGrange's sale of certain water systems to the Fayetteville Public Works Commission (PWC) in 1991 was set for determination in this general rate case by Order of the Commission dated February 14, 1991, Docket No. W-200, Sub 23, approving the transfer of the water systems to the PWC.

On July 14, 1993, the customer hearing was held as scheduled and 16 customers testified. The customers testifying were George Glann, James W. Smith, Karla Gaudet, Jerry L. Suggs, Michael Miller, Peggy Davis, Billy Ray Copper, Claude Nelson, Catherine Picone, Leon Lassiter, Martha Derr, Vernon Parker, Daryl Strother, Treva Cain, George Farris, and Cleveland Johnson. All the customers testifying were from the Cliffdale West water system. The customers testified regarding water quality, water line breaks, repair of roads back to Department of Transportation standards, the installation of an additional water storage tank, air in water, occasions of low pressure, and fire protection.

On August 4, 1993, LaGrange prefiled its report with the Commission in response to the customer testimony on July 14, 1993.

On August 6, 1993, Public Staff Utilities Engineer Bruce Vaughan filed supplemental testimony.

On August 6, 1993, LaGrange and the Public Staff filed a Joint Stipulation regarding the water service rates, the treatment of the gain on sale, treatment of previous tap fees collected, revision to the tariff for tap fees, SOC water analyses for the Cliffdale West water system being included in this rate order which would not be subject to later pass throughs or surcharges, and original cost rate base. This stipulation stated that the financial issues in the case had been settled subject to approval by the Commission.

The hearing was held as scheduled on August 6, 1993, and customers George Glann and James Smith appeared to testify to similar problems discussed at the previous public hearing. The Commission accepted the prefiled stipulation by LaGrange and the Public Staff. LaGrange presented the testimony of Hunter Chadwick and Dan Blackstock, the Company's field service supervisor, in support of the service report by LaGrange. Public Staff Utilities Engineer O. Bruce Vaughan testified as to his investigation of the service concerns expressed by the customers at the July 14, 1993 hearing and his recommendations.

WATER AND SEWER - RATES

Based on the information contained in the Commission files, the verified application, the testimony, the stipulation and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. LaGrange Waterworks Corporation is a public utility as defined in G.S. 62-3(23) and, as such, is subject to the jurisdiction and regulation of the North Carolina Utilities Commission. LaGrange is lawfully before the Commission seeking an increase in rates and charges pursuant to G.S. 62-133.

2. Monthly present rates, proposed rates and rates stipulated to by LaGrange and the Public Staff are as follows:

	Present	Proposed	Stipulated
Base Charge, zero usage	$3.00	$5.00	$5.00
Commodity Charge/1,000 gals.	.84	1.37	.98

3. The overall level of service provided by LaGrange is adequate. LaGrange has made service improvements and is continuing to make service improvements.

4. The Public Staff has conducted a complete investigation of LaGrange's rate base, reasonable operating revenue deductions and operating revenues. The Public Staff and LaGrange have stipulated that, based upon the Public Staff's investigation, an increase is necessary to increase rates of the base facility charge, zero usage to $5.00 per month per customer, and the commodity charge to $.98/1,000 gallons.

5. The test period established for use in this proceeding is the twelve months ending December 31, 1991.

6. The rates agreed to by the Public Staff and LaGrange in the stipulation are reasonable and should be approved.

7. As stipulated to by the parties, fifty percent of the gain related to the sale of water systems by LaGrange to PWC is being flowed back to ratepayers. The nonrecurring SOC test costs of $74,816 are being netted against the ratepayers' portion of the gain in calculating a net gain. The net gain of $37,051 is being amortized over six years with the net of tax unamortized balance being included as a deduction to rate base. This results in an annual amortization of $6,175 and a net of tax unamortized balance of $18,799.

8. LaGrange's applied for modification in its tap fees should be approved. The approved tap fees are as follows:

Residential - 5/8" X 3/4" When developer has not previously paid for tapping main and installing service line	$76 plus full gross up

Residential - 5/8" X 3/4" When developer has not previously paid for tapping main and installing service line	Actual cost of installation (includes tapping the main, installing service line, installing meter and meter box) plus full gross up
Meter sizes larger than 5/8" X 3/4"	Actual cost of installation (includes tapping the main, installing service line, meter, meter box and related equipment) plus full gross up

For the two tap fees that are actual cost plus full gross up, the Company shall give the person or entity applying for the connection a written statement of the amount of the connection prior to payment of the tap fees and the beginning of the work.

9. The original cost rate base for the test year ending December 31, 1991, is as follows:

Utility Plant in Service	$2,050,841
Acquisition Adjustment	(42,895)
Contributions in Aid of Construction	(1,356,168)
Accumulated Depreciation	(186,532)
Net Utility Plant in Service	$ 465,246
Cost Free Capital - Gain	(18,799)
Cost Free Capital - Excess Gross Up	(124,179)
Cash Working Capital	48,974
Average Tax Accruals	(7,111)
Original Cost Rate Base	$ 364,131

10. The rates contained in Appendix A attached hereto are reasonable and are approved.

EVIDENCE AND CONCLUSIONS

Based upon the entire record in this proceeding, the Commission is of the opinion that the rates agreed to by the parties in this proceeding are reasonable and should be approved. The Commission is also of the opinion that the service concerns expressed by the customers are being adequately addressed by LaGrange. LaGrange should continue its system upgrades to provide additional water storage and corrosion control.

Approval of the Joint Stipulation shall have no precedential value in future proceedings for LaGrange or any other public utility regulated by the North Carolina Utilities Commission, particularly with reference to the recovery of SOC test costs and the treatment of gain on sale.

IT IS, THEREFORE, ORDERED as follows:

1. That the Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138. Said Schedule of Rates is authorized to become effective for service rendered on and after the date of this Order.

2. That a copy of Appendix A and the Notice to Customers, attached hereto as Exhibit B, shall be mailed or hand delivered to all affected customers by LaGrange in conjunction with its next regularly scheduled billing process.

3. That LaGrange shall within 60 days file with the Commission written responses to the recommendations of Public Staff Engineer Bruce Vaughan in his August 6, 1993, supplemental testimony.

4. That this docket shall remain open for a period of 90 days after the date of this Order for any service complaints or studies and filing of such service reports as the Commission may require.

5. That the Joint Stipulation filed in this docket by LaGrange and the Public Staff on August 6, 1993, be, and the same is hereby, approved; provided, however, that such approval shall have no precedential value in future proceedings for LaGrange or any other public utility regulated by the North Carolina Utilities Commission, particularly with reference to the recovery of SOC test costs and the treatment of gain on sale.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of August 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

SCHEDULE OF RATES
for
LAGRANGE WATERWORKS CORPORATION
for providing water utility service
in
ALL SERVICE AREAS IN NORTH CAROLINA

Metered Rates:	Basic Facility Charge (no usage)	$5.00
	Commodity Charge	$ .98/1,000 gallons

Connection Charge:

Residential - 5/8" X 3/4" When developer has not previously paid for tapping main and installing service line	$76 plus full gross up

WATER AND SEWER - RATES

Residential - 5/8" X 3/4" When developer has not previously paid for tapping main and installing service line	Actual cost of installation* (includes tapping the main, installing service line, installing meter and meter box) plus full gross up
Meter sizes larger than 5/8" X 3/4"	Actual cost of installation* (includes tapping the main, installing service line, meter, meter box and related equipment) plus full gross up

*For connection fees which are actual cost, LaGrange shall give the person or entity applying for the connection a written statement of the amount of the connection prior payment of the tap fee and the beginning of the work.

Reconnection Charges:

If water service cut off by utility for good cause: $15.00
If water service discontinued at customer's request: $ 2.00

Bills Due: On billing date

Bills Past Due: 15 days after billing date

Billing Frequency: Shall be monthly, for service in arrears

Finance Charge for Late Payment: 1% per month when unpaid 25 days after billing date

Returned Check Charge: $10.00

Issued in accordance with authority granted by the North Carolina Utilities Commission in Docket No. W-200, Sub 25, on this the 12th day of August 1993.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-200, SUB 25

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by LaGrange Waterworks Corporation, Post Office Box 40707, Fayetteville, North Carolina 28309, For Authority to Increase Rates for Water Utility Service in all its Service Areas in Cumberland County, North Carolina) NOTICE TO CUSTOMERS

WATER AND SEWER - RATES

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing LaGrange Waterworks Corporation to charge increased rates for water service to all its water customers in North Carolina. The new approved rates are shown on the attached Schedule of Rates.

The new rates will increase the average monthly residential bill from $9.89 to $13.04, based upon the average monthly usage of 8,200 gallons.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of August 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-218, Sub 88

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Hydraulics, Ltd., Post Office Box 35047, Greensboro, North Carolina 27425, for Authority to Increase Rates for Water Utility Service in All of Its Service Areas in North Carolina	)	FINAL ORDER RULING ON EXCEPTIONS AND GRANTING PARTIAL RATE INCREASE

ORAL ARGUMENT HEARD: Monday, August 30, 1993, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman John E. Thomas, Presiding; and Commissioners William W. Redman, Jr., Charles H. Hughes, Laurence A. Cobb, Ralph A. Hunt and Judy Hunt

APPEARANCES:

For the Applicant, Hydraulics, Ltd.:

William E. Grantmyre, Attorney at Law, 1308 Bloomingdale Drive, Cary, North Carolina 27511

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On July 29, 1993, a Hearing Examiner entered a Recommended Order Granting Partial Rate Increase in this docket whereby Hydraulics, Ltd. (Hydraulics, the Applicant or the Company), was granted an increase in its revenues of $79,315 from its water utility operations.

On August 13, 1993, Hydraulics filed exceptions to the Recommended Order and requested oral argument. Hydraulics also requested that the Hearing Examiner's recommended rates be approved as interim rates pending the final decision of the Commission in this matter.

On August 20, 1993, the Commission issued Orders scheduling an oral argument on the exceptions and approving the Hearing Examiner's recommended rates as interim rates.

Oral argument was held on this matter on August 30, 1993. The Hearing Examiner's treatment of certain matters relating to: (1) bond expense, (2) volatile organic chemical (VOC) testing expense, (3) office rent expense, and (4) the appropriate risk factor to be used in establishing the Company's authorized margin were presented for reconsideration at the oral argument.

1. BOND EXPENSE:

In regard to the issue of bond expense, the Hearing Examiner's Recommended Order contained the following discussion and decision on this matter:

"Mr. Perkins testified that the difference between Hydraulics' interest expense to borrow the money to post bonds required by the Commission and the amount earned on the certificates of deposit posted is a reasonable, prudent, and necessary operating expense. According to Perkins Rebuttal Exhibit 1, the Company has posted $120,000 worth of bonds on which it earns $3,928 annually. This Exhibit also lists six debts and their corresponding interest rates along with the overall average. Applying the average interest rate on the debts listed on Exhibit 1 to $120,000 results in an annual cost of $12,660. The difference between this cost plus the fees charged by the holder of the certificates of deposit and the $3,928 earned on them is $9,516 and Hydraulics contends that this is a reasonable operating expense for inclusion in this proceeding. The Hearing Examiner disagrees.

"First, Hydraulics has not borrowed $120,000 in order to post the bonds. Three of the debts listed on Exhibit were incurred prior to the time Hydraulics posted the bonds; one represents $53,000 borrowed to purchase the company and another represents $21,330 to buy a vehicle. Only the three loans, including one from an employee and one from Mr. Perkins' brother at 10% interest, actually represent borrowings by Hydraulics to finance bonds. More importantly, even if Hydraulics had borrowed $120,000 to post the bonds, the interest expense would be treated no differently than any other interest expense incurred by the Company in order to do business.

"As Mr. Sessoms testified, interest expense is a return on investor supplied capital. Under the operating ratio method, the net income produced by the margin on operating expenses is the source from which the owner is allowed revenue to pay interest expense. If the owner is allowed recovery of interest expense and also receives a margin on operating expenses, the result would be a combination of the rate base method and the operating ratio method. The fact that Hydraulics chose to borrow some of the funds used to post the required bonds should not distinguish the Company from a utility whose owner put up personal funds in the form of equity for that purpose.

"The Hearing Examiner is aware of Commission practice that accords rate base treatment to bonds posted by utilities and includes interest earned on bonds in utility revenues. However, Hydraulics is not a rate base company. The Hearing Examiner is of the opinion that it would be inappropriate to allow a utility to receive a return on investor supplied debt capital, as a rate base company would, while also enjoying the benefits of the operating ratio method. The Hearing Examiner, therefore, concludes that the difference between interest earned on the bonds posted by Hydraulics and an imputed interest expense based on the total amount of the bonds is not a reasonable operating revenue deduction requiring a return."

Exception on Bond Expense

The Company disagreed with the Public Staff's and the Hearing Examiner's treatment of the bond interest expense. Hydraulics argued that, for an operating ratio company, the interest expense for the cost of bonding compared to other interest expense incurred by the utility is different because the bonds are posted by Hydraulics to comply with G.S. 62-110.3 and Rule R7-37 as a prerequisite for certification and should therefore receive different treatment. Specifically, the Company proposed that the reasonable level of operating expenses for use in this proceeding should include either bonding interest expense in the amount of $9,516, which is the difference between the Company's annual bonding interest expense of $12,660, on the $120,000 plus the fees charged by the holder of the certificates of deposit (CDs) and the $3,928 earned on the CDs, or, in the alternative, the Company proposed that operating expenses should include $2,400, which would be the minimum of 2% interest expense it would of had to pay to a commercial bonding company. Further, Hydraulics stated that G.S. 62-133.1 was enacted in 1973 and it does not define the components of operating expenses for the operating ratio methodology. Additionally, Hydraulics noted that the requirement for bonds for franchise certification was enacted in 1987, long after the operating ratio methodology was adopted.

Conclusion on Bond Expense

The Commission has carefully reviewed the evidence in this docket and concludes that the finding of the Hearing Examiner relating to the issue of bond interest expense is appropriate and should be affirmed.

The Commission agrees with the Public Staff and the Hearing Examiner that interest expense is a return on investor-supplied capital. Operating income is the source from which the utility is allowed revenue to cover interest expense on debt capital. Such interest is not an operating revenue deduction per se. If interest on debt capital is included as an operating expense, under traditional cost of service approaches, including the operating ratio methodology, there will be provisions for the double recovery of interest costs. The impropriety of such a result is further magnified if the utility is allowed a return on interest expense included as an operating revenue deduction, which would result under the methodology advocated by the Company. The Commission cannot find any reason to treat the bond interest expense differently from any other interest expense. If the Company's revenue requirements were being determined by the rate base/rate of return methodology, the rate base would be increased to reflect the inclusion of bonds posted pursuant to G.S. 62-110.3, and the level of present revenues would also be increased to reflect the interest income earned on the CDs. However, in this proceeding, the Company's rate base, which was not in controversy, was determined to be $369,004. Since the level of operating revenue deductions requiring a return as found reasonable in this case was substantially larger than the rate base, the Company benefited substantially by having its revenue requirement determined based on the margin on operating expenses methodology as opposed to the rate base/rate of return methodology.

2. VOC TESTING EXPENSE:

In regard to the issue of VOC testing expense, the Hearing Examiner's Recommended Order contained the following discussion and decision on this matter:

"Mr. Perkins testified that Hydraulics began VOC tests in the spring of 1990 at which time EPA required four consecutive quarterly samples from each entry point. Hydraulics completed one year of testing when DEH notified it that the requirement of four consecutive quarterly samples had been revised to only one sample from each entry point if that sample had no traces of VOCs. Hydraulics then revised its testing schedule for the remaining entry points. Mr. Perkins further testified that prior to the beginning of the VOC testing DEH had notified all the water companies which specific systems would have to be tested in 1990 and which would have to be tested in 1991. Therefore, by the time it was notified that the number of future tests had been reduced, Hydraulics had already done a major part of its testing.

"According to Perkins Rebuttal Exhibit 18, Hydraulics had spent a total of $34,713 for VOC tests through the end of the test year: $15,750 in 1990, $13,500 in 1991, and $5,463 in 1992. It is the Company's position that it should be allowed to recover this entire cost as an annual expense of $4,759, which consists of so-called 1990 and 1991 "unrecovered costs reamortized" plus 1992 costs amortized over five years.

"Mr. Brown testified that to arrive at a representative annual cost for VOC tests he had amortized the expected expenses over a period of time equal to the required frequency of testing. This resulted in an annual cost of $2,220.

"The difference between the Company's position and the Public Staff's position regarding VOC testing costs results from a fundamental disagreement over the purpose of an allowance for such costs in prior rate cases and whether the Company has recovered those costs. The Public Staff's position is consistent with its testimony and the Commission's decision in the most recent rate case involving Carolina Water Service, Docket No. W-534, Sub 111. The Recommended Order issued July 31, 1992, in that case states:

> The Commission continues to believe that VOC tests are regular tests and should not be included in deferred charges. Both parties [CWS and the Public Staff] agree that a representative level of VOC testing costs can be calculated and included in

> operating expenses. Since a normalized level of VOC testing expenses rather than a specific recovery of VOC testing costs has been allowed, there is no unamortized amount to be included in rate base. Therefore, consistent with our Order in CWS's last rate case, the Commission has determined that the Public Staff adjustment to reduce rate base by $51,865 for VOC costs is appropriate, and that no amount of deferred VOC testing charges should be included in rate base.

This language is unchanged in the final order. See North Carolina Utilities Commission Orders and Decisions, 82nd Report 387, 468-69 (1992).

"The Hearing Examiner agrees with the Public Staff that the Subs 70 and 81 orders did not authorize specific recovery of VOC testing expenses by Hydraulics. Moreover, the Hearing Examiner questions the Company's contention that it has not recovered the expenses for VOC testing that it incurred in 1990 and 1991. The Company received revenues from its customers and paid its bills during those years. It is not the task of regulation to track each individual component of the cost of service used in setting rates to ascertain whether that cost of that component actually materialized. Instead, the task of regulation is to determine a representative level of ongoing expenses with the understanding that some will turn out to be higher and others lower but that overall the utility will recover its costs. The Hearing Examiner, therefore, concludes that there is no unamortized balance of VOC testing cost to be recovered, and that a reasonable level of testing expense is $50,631, which includes a representative level of VOC testing expense of $2,220."

Exception on VOC Testing Expense

The Company disagreed with the Public Staff's and the Hearing Examiner's treatment of the VOC testing expense. Hydraulics stated that the $2,220 of VOC testing expense allowed by the Hearing Examiner does not accurately reflect the Company's historical cost nor the ongoing cost which will be required in January 1994. The Company believes that $4,759, based upon a five-year amortization, is the appropriate annualized VOC water monitoring costs to be included in operating expenses. Hydraulics argued that it should be allowed to recover prior 1990 and 1991 unrecovered costs reamortized of $3,666 and its normalized 1992 costs of $1,093 paid for VOC testing.

Conclusion on VOC Testing Expense

The Commission has carefully reviewed the evidence in this docket and concludes that the finding of the Hearing Examiner relating to the issue of VOC testing expense is appropriate and should be affirmed.

The Commission agrees with the Public Staff and the Hearing Examiner that the prior Hydraulics' Orders issued in Docket Nos. W-218, Subs 70 and 81, did not authorize specific cost recovery of VOC testing expenses but instead represented normalized levels of what those ongoing costs would be. The Company's proposal in this case, if allowed, would authorize a retroactive recovery of an unrecovered past expense which is generally not allowed by law; i.e., it would constitute retroactive ratemaking. The task of regulation is to determine a representative level of ongoing expenses with the understanding that some will turn out to be higher and others lower but that overall the utility is provided with a reasonable opportunity to recover its costs. In fixing the rates for a public utility, it is presumed that all reasonable ongoing expenses are recovered through the rates established and allowed by the Commission. The prior Commission Orders for Hydraulics issued in Docket Nos. W-218, Subs 70 and 81, were both stipulated cases where the Company and the Public Staff agreed on a representative ongoing cost of service. Furthermore, there is nothing in those Commission Orders that would tend to indicate that the Commission was creating a regulatory asset.

Additionally, the Commission reminds Hydraulics of the policy adopted by this Commission in its Final Order issued on August 27, 1993, in Docket No. M-100, Sub 120, which allows the Company to seek to recover additional testing requirements mandated by the Environmental Protection Agency (EPA) in a complaint proceeding.

3. OFFICE RENT EXPENSE:

In regard to the issue of office rent expense, the Hearing Examiner's Recommended Order contained the following discussion and decision on this matter:

"Mr. Perkins testified that Hydraulics leases its corporate headquarters at 706 North Regional Road in Greensboro from him and his wife at a monthly rental of $1,350. Prior to moving to this location in 1988, the Company leased office and warehouse space totaling 1,152 square feet from a third party for a base rental of $700 per month plus an annual rent escalation for the Consumer Price Index, plus a common area maintenance charge. The property currently occupied includes one acre of land, 1,483 square feet of office space, and parking space for at least 17 vehicles. According to Mr. Perkins, he and his wife purchased the property in their names since Hydraulics was unable to obtain bank financing in its own name without their personal guarantee. He contended that the monthly rental of $1,350 or $10.93 per square foot per year is reasonable and fair in comparison with comparable rents, the closest being the property next door at 704 Regional Road, which rents for $15.60 per square foot per year as shown on Perkins Rebuttal Exhibit 15.

"On cross-examination, Mr. Perkins stated that the purchase price of the office building was approximately $70,000 and the downpayment was approximately $5,000. He further stated that the area around the building generally consists of office buildings and vacant land and that there is no risk at all associated with owning the building.

"Ms. Grimsley testified that, since the sole shareholder of Hydraulics is, with his wife, the owner of the office property, the lease of the property to Hydraulics is an affiliated transaction. She adjusted the $1,350 monthly rental to reflect the actual monthly mortgage payment of $621 based on her belief that ratepayers should not be responsible for the high return on the Perkinses' investment. She added that, since Hydraulics is an operating ratio company, it will receive a return on rental expense as well as on expenses it incurs for building and property taxes, general liability insurance, and capital repairs that are normally regarded as the landlord's responsibility.

"The Hearing Examiner agrees with Ms. Grimsley that the lease of office and warehouse space by Hydraulics from the Perkinses is an affiliated transaction which deserves special scrutiny to ensure that ratepayers do not pay more than the reasonable cost of service. The evidence in this case shows that Hydraulics could have borrowed money and bought the property itself if the Perkinses had been willing to cosign for the loan, that there is little or no risk associated with owning the property, and that the Perkinses have cosigned for loans of Hydraulics in the past. The evidence further shows that the monthly rent is more than twice the monthly mortgage payment and thus produces a return that is in excess of the 92% return on equity that the Public Staff's recommended rates would produce. It is unreasonable for a utility to pay such a return to an affiliate and then to include the return as an operating revenue deduction on which a return is allowed.

"The Hearing Examiner does not agree with Mr. Perkins that the monthly rental for neighboring property is controlling to a determination of the reasonableness of the rent charged Hydraulics. If Hydraulics paid a non-affiliate $3,700 a month or $39,000 a year for 2,500 feet of office space like the tenant next door, the Hearing Examiner would still question the reasonableness of the expense as long as buying the property was an option as it clearly appears to be. The Hearing Examiner, therefore, concludes that the reasonable level of expense before non-utility allocation is $7,452 for office rent and $2,880 for warehouse rent."

Exception on Office Rent Expense

The Company disagreed with the Public Staff's and the Hearing Examiner's treatment of the office rent expense. Hydraulics argued that the office rental payment of $10.93 per square foot per year ($1,350 per month or $16,200 per year) is well below market as indicated by the $15.60 per square foot per year rent on the property next door and is fair and reasonable and should be approved as a reasonable operating expense. The Company believes the Commission should look at the reasonableness of the transaction between the utility and its affiliates.

Conclusion on Office Rent Expense

The Commission has carefully reviewed the evidence in this docket and concludes that the finding of the Hearing Examiner relating to the issue of office rent expense is inappropriate and should be reversed.

The basis of Public Staff witness Grimsley's adjustment to remove the difference between the actual rental payment of $1,350 and the monthly mortgage payment of $621 (these amounts are before non-utility allocation, i.e. construction business is also operated by Mr. Perkins out of the same office building) seems to rely primarily on the affiliated nature of this transaction, without giving any consideration to the reasonableness of the rent actually paid in comparison to the Greensboro rental market.

Hydraulics' President, Manuel Perkins, testified that in 1988 he and his wife purchased the property in their individual names, as Hydraulics was unable to obtain bank financing in the Company's name. He testified that no bank would loan money to Hydraulics for this property without the personal guarantee of Manuel Perkins and wife, Chris Perkins.

Witness Perkins testified that the office property has one acre of land, office space of 1,483 square feet and parking space for at least 17 vehicles. He testified that it was necessary that there be 17 parking spaces as in the mornings when water operators are in the office receiving their assignments, there are seven field service vehicles plus Frank Ahalt, who does part-time meter reading. He testified that there also must be parking places for six office employees and a minimum of three parking places available for customers, vendors, and regulators such as Division of Environmental Health, the Public Staff and other governmental agencies. He testified that the need for such a large parking area to accommodate all the service vehicles, plus the office staff and visitors is a major consideration as to the value of the office lease. Witness Perkins testified that it is impossible in the Greensboro area to obtain such a large number of parking places in normal commercial leases where the tenant leases space in a multi-tenant building or space in a strip office complex.

Witness Perkins testified that the rent paid by Hydraulics of $1,350 per month totals $10.93 per square foot per year. In Perkins Rebuttal Exhibit 15, the Company introduced into evidence a March 30, 1993, letter from AUA, Inc., setting forth the details on the lease of the property at 704 North Regional Road, which is contiguous and immediately next door to the office property of Hydraulics at 706 North Regional Road. The letter indicated that AUA, Inc., pays $15.60 per square foot per year for its office space and that AUA, Inc., pays all the additional rental expenses Hydraulics pays. However, according to witness Perkins, AUA, Inc., also pays for general liability insurance for the protection of the landlord which Hydraulics does not pay. The testimony was uncontroverted that the Hydraulics' office building and the AUA, Inc., building are comparable buildings and properties with the one exception, the parking lot at the AUA, Inc., property is paved.

Further, witness Perkins testified that the property at 704 North Regional Road is the most comparable rental property to the property leased by Hydraulics at 706 North Regional Road. He testified that both are stand alone buildings that have adequate parking and each has an identical location being next door to the other. Witness Perkins testified that it was necessary for Hydraulics to move to this new office location in 1988 as Hydraulics had far outgrown its previous rental property. He further testified that it would soon be necessary to expand the current facility.

Based upon the foregoing, the Commission concludes that the monthly rental of $1,350 paid by Hydraulics less the adjustment for the portion of the building used for nonutility construction operations is reasonable to include as an operating expense in this proceeding. It was uncontroverted evidence that Hydraulics could not purchase this property in its own name even using this business property as collateral. The rental paid to the owner, Manuel Perkins and wife, Chris Perkins, is below market at $10.93 per square foot per year compared to the adjoining property rental payment of $15.60 per square foot per year. The evidence was uncontroverted that these are comparable properties with the only difference being that the parking lot next door is paved with the Hydraulics parking lot being gravel and grass.

In this case the Commission believes that the transaction between the utility and its affiliate is reasonable for the utility, as the rental paid is below the fair market rental rate demonstrated by the rent on the comparable adjoining property and considering that the only way that Hydraulics could have received a loan to purchase this property would have required the Perkinses to be cosigners on the loan.

4. RISK FACTOR:

In regard to the issue of the appropriate risk factor, the Hearing Examiner's Recommended Order contained the following discussion and decision on this matter:

"The evidence for these findings of fact is contained in the testimony of Mr. Perkins, Mr. Sessoms, and Ms. Grimsley, and in the Recommended Order of January 17, 1986, and the final Order of March 10, 1986, in Docket No. W-218, Sub 32, and the Recommended Order of December 21, 1990, in Docket No. W-883, Sub 12, of which the Hearing Examiner has taken judicial notice.

"Mr. Sessoms recommended that Hydraulics be granted a 9.5% margin on operating revenue deductions requiring a return. He stated that he derived a margin above expenses by combining the risk-free rate of 10-year U. S. Treasury bonds averaged over the most recent 26-week period with a three percentage point factor to adjust for risk.

"Mr. Perkins testified that Hydraulics agrees with the 6.5% risk free rate but believes a risk factor of at least 5% is appropriate. He stated that Hydraulics cannot borrow money from any bank based on its own credit and assets and that lending institutions require all loans to Hydraulics to be personally guaranteed by him and his wife. He further stated that it was necessary to place a mortgage on the family home in order to obtain credit and loan funds for Hydraulics. Mr. Perkins also testified that Hydraulics has continued to struggle to make its payroll and to pay water monitoring laboratory fees and suppliers. This, he contended, demonstrates a much greater risk factor than 3%.

"Mr. Perkins further testified that the increasingly stringent requirements of the SDWA have materially increased the risks for Hydraulics and all other water utilities. He stated that the Company will be faced in 1994 with the monitoring requirements for VOCs and SAC/Pesticides which would result in cash payments of approximately $275,000 for systems with a population greater than 100 and a virtually identical requirement in 1995 for systems with populations less than 100. In addition, if Hydraulics exceeds the EPA action levels for lead and copper monitoring in 1993, the Company will be required to begin expensive corrosion studies and treatment programs, and if there are violations of the SDWA contaminant levels, the Company faces the loss of wells.

"Mr. Sessoms testified that the personal financial situation of a utility investor is not relevant to the Commission's determination of the appropriate rate of return or the margin on expenses. He stated that, while the owner or an investor may have to provide personal guarantees when borrowing money from a bank to invest in a utility, there is no way to know the investor's entire financial holdings. He also stated that it was fairly typical for owners of water companies to borrow funds for investment in utility systems. In this regard, it was his opinion that Hydraulics was of average risk compared to other water companies that have received the 3% presumptive risk factor. He further stated that just as he would not decrease the return or margin because the investor or investors were wealthy, neither would he recommend a higher return because of an investor's difficulty in raising funds to invest in a utility. In other words, ratepayers should not pay higher or lower rates depending on the personal financial situation of investors. The risk of a utility recovering its cost of capital or its annual operating expenses should not be affected by the personal financial situation of an owner.

"Mr. Sessoms also testified that several factors should be taken into account in judging the adequacy of a margin or return: quality of service, the level of inflation, interest coverage, and the income level after interest expense. With respect to interest coverage and income level, he stated that the pre-tax interest coverage produced by the Public Staff's recommendation in this case is approximately 8.3 times and that the Company would earn a return on equity of approximately 92% under this recommendation. He stated that while the interest coverage ratio and return on equity seem unusually high, one must remember that the net income is produced by allowing the margin on the expense level, which is two to three times the level of rate base. He stated that, in his opinion, if the 9.5% margin on expenses increased for any reason, the 8.3 times pre-tax interest coverage and 92% return on equity would be increased unnecessarily.

"When asked on cross-examination whether he was aware of a 1986 Hydraulics rate case in which the Commission ruled that a 5% risk factor was appropriate and a 1985 Scientific Water case in which the Commission ruled that a 4% risk factor was appropriate, Mr. Sessoms stated that he was but that he was also aware of a more recent Scotsdale rate case which more accurately reflected economic theory and risk. With respect to increased testing requirements, Mr. Sessoms stated that the Public Staff had allowed an ongoing reasonable and representative level of expense and, therefore, he did not see these requirements as relevant to the risk of the utility. Likewise, he stated, the approximately $275,000 that will be needed in 1994 and 1995, and the cost of replacing wells and installing treatment equipment if violations are found, will just increase the amount of capital that must be invested and will not necessarily increase the risk.

"The Hearing Examiner is mindful of the Commission's decision in rate case Docket No. W-218, Sub 32, allowing Hydraulics a 5% risk factor. In that case, which was heard in 1985, the Hearing Examiner stated, in part, as follows:

> The current financial status of the Company coupled with the fact that it was necessary for the owner and his wife to cosign a loan and pledge as collateral the family home in order to obtain necessary financing for the water system leads the Hearing Examiner to conclude that a risk factor of 5% is more appropriate in this case than the 3% recommended by the Public Staff. ... The Hearing Examiner concludes that the relative risk associated with Hydraulics exceeds the associated risk of the average water utility in this State and thus that a risk premium exceeding that granted to most water utilities in this State is warranted.

Recommended Order issued January 17, 1986. By Order issued March 10, 1986, the Commission affirmed the Recommended Order, stating, "The financial instability of this Company clearly justifies the use of a 5% risk factor." The Hearing Examiner is of the opinion that Hydraulics' financial condition today is quite different from its condition in the mid-1980's. The Company's operations have increased from serving 1,235 customers in 31 systems in 11 counties to serving 3,304 customers in 76 systems in 19 counties. Its operating revenues have increased nearly fourfold. While mindful of this earlier decision, the Hearing Examiner agrees with Mr. Sessoms that the more recent decision in Docket No. W-883, Sub 12, involving Scotsdale Water and Sewer, Inc., contains sounder reasoning. It states:

> While the owner of Scotsdale may have a second mortgage on his home due to obtaining loans for his utility, the Commission does not know his entire financial holdings, nor why such holdings or lack of holdings exist. Just as the Commission would not decrease the return allowed to a utility because the owner was wealthy, neither should it increase the return to a utility because the owner has a second mortgage on his home. Further, to allow a higher return for such reasons would encourage such leverage and provide for unsound regulatory policy.

Recommended Order issued December 21, 1990. The Hearing Examiner is simply unable to conclude that the risk associated with Hydraulics exceeds that associated with the average water utility in North Carolina.

"The question remains, of course, whether the risk associated with all utilities has increased in recent years. It is undeniable that water utilities are subject to more stringent testing requirements than ever before and that the cost of meeting these requirements has increased the cost of providing service. It is equally undeniable, however, that the ratepayers and not the utilities will ultimately bear this burden. Mr. Sessoms pointed out the generosity of the operating ratio method to Hydraulics' investor. It would be altogether unjustified and unreasonable to increase the return on the grounds of some unsubstantiated change in risk to the industry as a whole. The Hearing Examiner, therefore, concludes that a risk factor of 3% is reasonable, which, when added to the risk-free rate of 6.5%, produces a 9.5% return on operating revenue deductions."

<u>Exception on Risk Factor</u>

The Company disagreed with the Public Staff's and the Hearing Examiner's position that a 3% risk factor was appropriate. Hydraulics argued that a 3% risk factor is too low and that a 5% risk factor would be appropriate, with an 11.5% margin on operating revenue deductions. The Company stated that the only time the Commission has had an opportunity to determine the appropriate risk factor for Hydraulics was in Docket No. W-218, Sub 32, issued March 10, 1986. In that Order, the Commission affirmed the 5% risk premium deemed appropriate by the Hearing Examiner. In that case the Company noted that the factors so stated to support this position were:

1. It was necessary for the owner and his wife to cosign a loan and pledge the family home as collateral in order to obtain financing for the water system. The proceeds of the Company financing were used to pay past due gross receipts tax, a portion to pay accounting fees and a portion to buy the remainder of the outstanding stock in the Company.

2. Hydraulics had been experiencing difficulty meeting obligations such as payroll and tax liabilities, and purchases for maintenance and plant improvements must be made on a cash basis due to the Company's inability to obtain financing.

The Company argued that virtually all the same financial risk factors exist in the current case. Specifically, the Company at the oral argument stated that the same mortgage that the Commission spoke of in the 1986 Order still exists. The Company further stated it had cash flow problems as evidenced by a particular instance where a lab refused to give the Company monitoring results prior to payment and the Company noted it had difficulties at times making payroll. Additionally, in its written exceptions, the Company had also stated that the 3% risk factor was no longer appropriate because of the increased risk associated with the Safe Drinking Water Act (SDWA), but at the oral argument the Company admitted that now with the issuance of the Commission's Order in Docket No. M-100, Sub 120, issued on August 27, 1993, this would take care of the Company's testing costs so it is not really a risk of being able to come up with the money to do the testing, but if there are violations, they must still go out and replace wells, and they have already had to replace two wells. Further, the Company noted that the current proceeding did not contain any justification as to why the 3% risk factor is appropriate.

Conclusion on Risk Factor

The Commission has carefully reviewed the evidence in this docket and concludes that the finding of the Hearing Examiner relating to the issue of the appropriate risk factor is inappropriate and should be amended to reflect adoption of a 5% risk factor.

The evidence of Hydraulics was that Hydraulics cannot, based on its own credit and assets, borrow money from a bank. In order to obtain credit and loan funds for Hydraulics, it was necessary for Manuel Perkins, the owner of all the shares of stock of Hydraulics, to place a second mortgage on the family home which is owned by he and his wife. He testified that all lending institution loans to Hydraulics must be personally guaranteed by him and his wife.

Witness Perkins testified that Hydraulics has continued to have difficulties making payroll. He testified that payroll checks to certain employees have been withheld as funds were not available. He stated that the Company continues to experience difficulty paying water monitoring laboratory fees. Witness Perkins testified that laboratory fees are increasing and this increases the risk. He testified that Webb Laboratory refused to give Hydraulics its VOC testing results until paid.

Witness Perkins testified that the Company has experienced difficulty paying suppliers which furnish important services and/or materials for the water systems. Further, he stated that Hydraulics has faced and continues to face possible cut offs of materials and supplies because of the inability to pay these accounts.

Witness Perkins also testified that the Company's risk have increased since the Commission adopted the 5% risk factor in 1986. He noted that the SDWA has added many more testing requirements. He testified that the Company has already lost two wells located at Deer Path and Canterbury water systems because of water monitoring maximum contaminant level violations. Further, he testified that Hydraulics is facing the risk of not being able to obtain the necessary capital to meet the new synthetic organic chemical (SOC), pesticide and VOC testing requirements which will require $275,000 in laboratory testing fees in 1994 and $275,000 in 1995.

Public Staff witness Sessoms testified that Dr. Stevie, former Chief Financial Analyst of the Public Staff, used a 3% risk factor in his testimony in the Montclair Water Company general rate case in Docket No. W-173, Sub 14, in his determination of an appropriate margin on operating revenue deductions requiring a return. Witness Sessoms testified that Dr. Stevie had not directly documented in his testimony where the 3% risk factor came from. However, witness Sessoms stated that the 3% factor is a presumptive risk factor which presupposes the average risk of owning a water company. Further, witness Sessoms testified that the 3% is a rather subjective determination necessitated because of the lack of capital market data on publicly traded water companies. Mr. Sessoms testified that he was unable to recall whether the Public Staff had ever recommended a risk factor other than 3% in this type of analysis.

Public Staff witness Brown on cross examination testified that if Hydraulics was unable to raise the capital to do the required SOC, pesticide and polychlorinated biphenyis (PCB) monitoring in 1994, they would be subject to fines. Further, he testified that fines and penalties are not allowed in the ratemaking process. Witness Brown stated that there was a great deal of new testing required since Dr. Stevie's 3% risk factor was recommended in 1978 or 1979. These new tests include the monitoring of VOCs, SOCs, PCBs, pesticides, trihalomethanes, asbestos, nitrates, and nitrites. Witness Brown testified that if water monitoring shows a violation of a maximum contaminant level and the violation is high enough, then the water company must do something to alleviate the situation such as install removal equipment or come up with a new source of water. He testified that these are possibilities water companies did not face in 1978 and 1979.

Based upon a careful review of the evidence, the Commission concludes that a 5% risk factor is appropriate for Hydraulics in this proceeding. The Commission takes judicial notice of the last Hydraulics rate case in which this issue was litigated in Docket No. W-218, Sub 32. In that case, by Order dated March 10, 1986, the Commission approved a 5% risk factor.

The Commission in its March 10, 1986, Order stated as follows:

"The Commission notes that the margin on operating revenue deductions methodology of determining operating ratio was introduced several years ago by the Public Staff and has been accepted routinely by the Commission in water cases. The methodology itself obviously has merit. However, the Public Staff has generally not altered its risk premium of 3% for any water company. It is recognized that the risk factor is judgmental based on the overall risk of the company involved. The 3% risk factor has been advocated by the Public Staff for small, large, financially stable, financially unstable, well managed and poorly managed systems alike. The Commission believes proper consideration of these factors warrant varied risk factors for individual companies since all water companies do not face the same risk. The financial instability of the Company clearly justifies the use of 5% risk factor. Thus the Commission affirms the Hearing Examiner's decision in this regard."

The Commission finds that the factors considered in assessing the appropriate risk factor for Hydraulics in the Commission Order of March 10, 1986, for the most part, still exist. There is still a second mortgage on the home of the owner of Hydraulics, the proceeds of which were used partially to pay operating expenses of Hydraulics. Hydraulics continues to have difficulty paying its suppliers which furnish important services and/or materials for the water systems. Hydraulics still faces possible cut offs of materials and supplies. Hydraulics still has difficulty making payroll. Hydraulics now has difficulty paying laboratories for water analyses and results have been withheld until the laboratory received payment. Additionally, as stated by Public Staff witness Brown, there has been a significant increase in water testing requirements since the 3% risk factor was recommended by Dr. Stevie. Water utilities now face new challenges that if there are maximum contaminant level violations for any of the numerous new SDWA contaminants, then the water utility must do something to correct the problem such as install removal equipment or find an alternate source of water and if the maximum contaminant level violation is high enough, the utility may be fined if the contaminant is not removed or if an alternate water source is not found. The Commission concludes that a risk factor of 5% is appropriate for Hydraulics in this proceeding and will result in a margin of 11.5% on operating revenue deductions requiring a return. This 11.5% margin is the combination of the parties' agreed to risk-free rate of 6.5% and the 5% risk factor.

OVERALL CONCLUSION:

Based upon the foregoing conclusions, wherein the Commission has found it appropriate to reverse the Hearing Examiner's decisions on the issues of office rent expense and the risk factor, the Commission finds it appropriate to modify certain findings of fact that have been recommended by the Hearing Examiner. Specifically, the Commission makes the following findings of fact to replace the corresponding findings of fact contained in the Hearing Examiner's Recommended Order.

MODIFIED FINDINGS OF FACT

12. Hydraulics' reasonable level of operating revenue deductions requiring a return, after accounting and pro forma adjustments, is $905,111.

[Parts 12.a through 12.d and 12.f through 12.h of this finding shall remain as written by the Hearing Examiner.]

e. The monthly rent paid by Hydraulics for its office building and warehouse less the adjustment for the portion of the building used for nonutility construction operations is a reasonable operating revenue deduction requiring a return. The reasonable level of expense for office and warehouse rent is $17,172.

15. A margin of 11.50% on operating revenue deductions requiring a return is just and reasonable for Hydraulics.

16. Hydraulics should be allowed to increase its rates to produce an increase in annual gross revenues of $122,749.

17. The following rates will produce annual gross revenues of $1,099,631 and will allow Hydraulics the opportunity to earn the 11.5% return on operating revenue deductions found just and reasonable:

<u>Flat Rate Monthly</u>	$22.05
<u>Metered Rate Monthly</u>	
Base charge, zero usage	$10.14
Usage charge (per 1,000 gallons)	$ 3.16

As stated in the above findings of fact, the Commission finds that operating revenues of $1,099,631 will produce the 11.5% margin on operating revenue deductions found reasonable herein. The following schedule summarizes the gross revenue and margin that the Company should have a reasonable opportunity to achieve after giving effect to the rate adjustment as required herein.

HYDRAULICS, LTD.
DOCKET NO. W-218, SUB 88
STATEMENT OF NET OPERATING INCOME FOR RETURN AND
MARGIN ON OPERATING REVENUE DEDUCTIONS REQUIRING A RETURN
For the Test Year Ended November 30, 1992

Item	Present Rates	Approved Increase	Approved Rates
Operating Revenues:			
Metered & Unmetered Revenues	$976,882	$122,749	$1,099,631
Miscellaneous Revenues	10,589	-	10,589
Uncollectibles	(6,731)	(845)	(7,576)
Total Operating Revenues	980,740	121,904	1,102,644
Operating Revenue Deductions:			
Total Operating & Maintenance Expense	783,971	-	783,971
Depreciation Expense	87,903	-	87,903
General Taxes	33,237	-	33,237
Operating Revenue Deductions Requiring a Return	905,111	-	905,111
Regulatory Fee	834	103	937
Gross Receipts Tax	39,230	4,876	44,106
State Income Tax	2,756	9,062	11,818
Federal Income Tax	3,392	33,191	36,583
Total Operating Revenue Deductions	951,323	47,232	998,555
Net Operating Income	$29,417	$ 74,672	$104,089
Operating Revenue Deductions Requiring a Return			$905,111
Margin on Operating Revenue Deductions Requiring a Return			11.50%

IT IS, THEREFORE, ORDERED as follows:

1. That Hydraulics is authorized to increase its rates for water utility service to all of its customers effective for service rendered on and after the date of this Order.

2. That the Schedule of Rates attached as Appendix A is approved and deemed to be filed with the Commission pursuant to G.S. 62-138, effective for service rendered on and after the date of this Order.

3. That a copy of the Notice to Customers, attached as Appendix B, be mailed or hand delivered to all customers in conjunction with the next regularly scheduled billing on and after the date of this Order.

4. That, except as modified herein, the Hearing Examiner's Recommended Order heretofore entered in this docket on July 29, 1993, is hereby affirmed and shall become effective and final on and after the date of this Order.

5. That, except as granted herein, the exceptions to the Hearing Examiner's Recommended Order filed in this docket by the Applicant be, and are hereby, otherwise denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of November 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Commissioner William W. Redman, Jr., dissenting in part and concurring in part.
Commissioner Charles H. Hughes, dissenting in part and concurring in part.
Commissioner Allyson K. Duncan did not participate in this decision.

APPENDIX A

SCHEDULE OF RATES
for
HYDRAULICS, LTD.
for providing water utility service in
ALL OF ITS SERVICE AREAS IN NORTH CAROLINA

Monthly Metered Rates:

Base charge, zero usage	\$10.14, minimum
Usage charge, per 1,000 gallons	\$ 3.16

Monthly Unmetered Rates: (Shade Tree Acres, Walker Heights). \$22.05

Connection Charge:

Meter Fee - 5/8" x 3/4" meter - \$500.00
Larger than 5/8" x 3/4" meter - Actual Cost of Installation

No connection charges shall be collected for Apple Hill, The Meadows, and Staffordshire Estates water systems.

Main Extension Fee per Single Family Dwelling: \$625.00

(The full gross up will be added to these connection charges).

Reconnection Charges:

If water service cut off by utility for good cause:	\$25.00
If water service discontinued at customer's request:	\$15.00
If customer without authorization reconnects after the water has been cut off by the utility for good cause:	\$50.00

Returned Check Charge: \$15.00

Bills Due: On billing date

Bills Past Due: 15 days after billing date

Billing Frequency: Shall be monthly for service in arrears

Finance Charge for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 88, on this the 24th day of November 1993.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

DOCKET NO. W-218, Sub 88

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Hydraulics, Ltd., Post Office Box 35047, Greensboro, North Carolina 27425, for Authority to Increase Rates for Water Utility Service in All of Its Service Areas in North Carolina	)	NOTICE TO CUSTOMERS OF NEW RATES

BY THE COMMISSION: Notice is hereby given that the North Carolina Utilities Commission has granted a rate increase to Hydraulics, Ltd., for water utility service provided in all its service areas in North Carolina. This decision was based upon evidence presented at the public hearings held on April 6, April 7, and April 8, and May 18, 1993, in Newton, Greensboro, Morehead City, and Raleigh, North Carolina, respectively and upon the oral arguments on exceptions presented to the Commission by the Company and the Public Staff on August 30, 1993 in Raleigh.

The new rates approved by the Commission will replace the interim rates which have been in effect since August 20, 1993. The new rates are as follows and are effective for service rendered on and after November 24, 1993.

Monthly Metered Rates:

Base charge, zero usage	$10.14, minimum
Usage charge, per 1,000 gallons	$ 3.16

Monthly Unmetered Rates: (Shade Tree Acres, Walker Heights) $22.05

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of November 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

COMMISSIONER WILLIAM W. REDMAN, JR., DISSENTING IN PART AND CONCURRING IN PART. I respectfully dissent from the decision of the Majority to overrule the Hearing Examiner with respect to the proper level of cost to be included in the Company's cost of service for rent of its corporate headquarters. The additional rent expense approved by the Majority unnecessarily and inappropriately increases the rates charged the Company's customers by $9,885 annually.

Hydraulics leases its corporate headquarters from Manuel Perkins, its sole shareholder, and his wife, Chris Perkins, which raises a question as to whether the lease-rental agreement reflects an arms-length bargaining process. Traditionally, it has been a long-standing practice of this Commission to review transfer pricing arrangements between utilities and affiliated interests, such as the matter here under review, with special scrutiny. In evaluating the reasonableness of such pricing arrangements the Commission has considered the transfer prices of affiliates in comparison to the prices charged by nonaffiliated providers of similar goods and services, and the Commission has carefully weighed the levels of profits realized by the unregulated affiliated interests arising from their dealings with regulated utilities.

In determining the levels of transfer prices properly includable as a component of a utility's cost of service, this Commission has a long history of setting such costs at levels which would allow the affiliated interest to recover all of its reasonable costs incurred in providing the goods and services, including a reasonable profit or, stated alternatively, a reasonable return on its investment. The Commission to a vast extent has given very little weight to prices charged for comparable goods or services available from nonaffiliated interests and properly so. To the extent that the Commission has considered comparable prices of nonaffiliated interests, such prices have been used almost exclusively as benchmarks to establish the maximum prices of goods and services that a utility should be allowed to include in its cost of service, even though prices established by use of such benchmarks might not allow affiliates a reasonable return on their investments. When situations such as those arise, it is most often the result of attempts to shift profit from the regulated utility to the unregulated affiliate or conversely to shift uneconomic costs from the unregulated affiliate to the regulated utility.

In this docket, the Hearing Examiner included a level of cost in Hydraulics' cost of service associated with the lease of its corporate headquarters that would allow Mr. and Mrs. Perkins an annual return of 14% on their equity investment in that facility. Under the Majority's decision, Mr. and Mrs. Perkins, according to the uncontroverted testimony of the Public Staff, will earn an annual equity return in excess of 92% on their equity investment in Hydraulics' corporate headquarters. It is my view that the 14% return provided for by the Hearing Examiner is eminently reasonable and that the 92% plus return allowed by the Majority is grossly excessive, particularly in view of the fact that Mr. Perkins testified on cross-examination that there is <u>no risk</u> at all associated with owning the corporate headquarters building.

There are also other factors present in this case which serve to underpin my view that the Hearing Examiners' decision adequately compensates Mr. and Mrs. Perkins for Hydraulics lease of its corporate headquarters building. For example, the Hearing Examiner included in the Company's cost of service (1) an amount equal to the annual mortgage payment on the headquarters building, including principal and interest, (2) an operating margin allowance of 9.5% on said mortgage, which has now by virtue of the Commission's decision on exceptions been increased to 11.5%, (3) property taxes on the building and grounds, (4) general liability insurance on the building structure and grounds, and (5) cost associated with building repairs. Due to the fact that Hydraulics' cost of service is determined on the basis of the operating ratio methodology, the operating margin allowance of 11.5% is included on all operating revenue deductions, including all of those costs related to Hydraulics' corporate headquarters building.

Further, in my mind the risk premium of 5% embodied in the operating margin allowance of 11.5% allowed Hydraulics by the Commission was intended to and does fully compensate Mr. and Mrs. Perkins for acting as personal guarantors for bank loans made to the Company. The validity of this point of view is readily apparent from even a casual reading of the Commission's instant Order.

As a holder of a certificate of public convenience and necessity to provide monopoly services within its franchised territory, a public utility has an obligation to provide a reasonable quality of service at the lowest possible economically efficient cost. It is the Commission's responsibility as a surrogate for competition to insure that a utility accomplishes the foregoing objective and that in so doing it does not abuse its monopoly status. In this instance, it is clear that Mr. Perkins has structured the acquisition of the corporate headquarters building and its subsequent lease to Hydraulics in a manner so as to maximize profit at the expense of the Company's ratepayers. Mr. Perkins, Hydraulics, and the Majority seek to justify such action by contending (1) that the reasonableness of the rental payment for the corporate headquarters building should be determined solely by use of certain price comparisons and (2) that the transactions were structured appropriately since Hydraulic was unable to obtain bank financing in its own name without the personal guarantees of Mr. and Mrs. Perkins.

Price comparisons are useful in establishing ceiling prices to be used in determining the appropriate levels of costs to be included in a regulated utility's cost of service when evaluating the reasonableness of transfer prices between a utility and affiliated interest. However, such price comparisons standing alone are of very little value when one undertakes to determine whether goods and services needed in the providing of public utility services could have in fact been acquired or provided in a more economical manner by the utility itself in lieu of obtaining the goods and services from another entity, notwithstanding questions concerning the propriety of self-dealings involving affiliated interests.

Uncontroverted evidence in this case clearly shows that the cost which would have been incurred by Hydraulics had it purchased the building in question would have been approximately one-half of the cost now being imposed on the utility and consequently its ratepayers by the utility's sole shareholder, his wife, and the Majority. It is therefore clearly evident that substantial cost savings to the utility and its customers would have resulted had Hydraulics itself acquired the subject property. That brings us to the question of the Majority's justification concerning Hydraulics inability to obtain bank financing in its own name without the personal guarantees of Mr. and Mrs. Perkins.

Mr. and Mrs. Perkins in the past have personally guaranteed bank loans made to Hydraulics. On cross-examination in this docket, Mr. Perkins testified that there is no risk at all associated with owning the corporate headquarters building. Why then, one might ask, would Mr. and Mrs. Perkins now be unwilling to act as guarantors of a bank loan to Hydraulics for the purpose of purchasing the subject property? The answer, of course, is clear. If Mr. and Mrs. Perkins had acted as guarantors of a bank loan to Hydraulics they would have by such action deprived themselves of an opportunity to realize the excessive profits that they have now been awarded by the Majority as a result of their self-dealings; a result which I find to be totally inappropriate and unacceptable.

For the foregoing reasons I dissent from the decision of the Majority to overrule the Hearing Examiner with respect to the proper level of cost to be included in the Company's cost of service for rent of its corporate headquarters.

I concur in and fully support the other findings and conclusions reached by the Commission in addressing all other matters and issues before it in this regard.

Commissioner William W. Redman, Jr.

COMMISSIONER CHARLES H. HUGHES, DISSENTING IN PART AND CONCURRING IN PART. I respectfully dissent from the decision of the majority not to include as an operating revenue deduction certain interest expense associated with $120,000 worth of bonds posted by the Company with the Commission. Such bonds are required by Commission Rule.

I understand and agree that provision for the recovery of interest expense incurred in providing public utility services by an investor-owned public utility is typically provided for in cost of service determinations by inclusion of a component of cost representing the utility's cost of capital. Under the rate base rate of return ratemaking methodology the specific level of cost included for that purpose is a function of the utility's rate base and its authorized rate of return. When the operating ratio ratemaking methodology is employed, such as in the instant case, the specific level of capital cost or margin included in the cost of service equation is a function of the utility's total operating revenue deductions and its authorized margin. That is to say that under the operating ratio ratemaking methodology a utility is allowed a margin on its operating revenue deductions as opposed to a rate of return on its rate base. In substance, the operating income that results under either method is intended to cover all reasonable capital costs, including interest expense associated with debt capital.

It is my view that, in the instant case, the operating ratio methodology used by the Commission does not adequately compensate Hydraulics for interest cost it has actually incurred in complying with certain mandatory requirements of this Commission; i.e., only cash will be accepted as bond collateral. If the Commission was willing to accept a bond other than cash, it would have a cost and that cost would be properly includable in the Company's cost of service. Interest expense is the bond cost when only cash can be given to satisfy the bonding statute. I would have included the interest cost associated with the bonding requirements of the Commission as an operating expense in developing the Company's cost of service, thereby assuring that such cost was in fact included in determining the Company's overall revenue requirement.

I concur in and fully support the other findings and conclusions reached by the Commission in addressing all others matters and issues before it on reconsideration.

Commissioner Charles H. Hughes

DOCKET NO. W-274, SUB 75

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina 27519, for Authority to Increase Rates for Water Utility Service in All Its Service Areas in North Carolina	)	ORDER APPROVING PARTIAL INCREASE IN RATES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on August 3, 1993, at 7:00 p.m. and August 17, 1993, at 9:30 a.m.

BEFORE: Commissioner Charles H. Hughes, Presiding, Chairman John E. Thomas and Commissioner Laurence A. Cobb

APPEARANCES:

For the Applicant:

Robert F. Page, Attorney at Law, Crisp, Davis, Page, Currin and Nichols, 4011 Westchase Blvd., Suite 400, Raleigh, North Carolina 27607

For the Public Staff:

Victoria O. Hauser, Staff Attorney, Public Staff, North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

BY THE COMMISSION: On March 12, 1993, Heater Utilities, Inc. (Heater, Company, or Applicant), filed the above-referenced application. By Order issued on April 7, 1993, the Commission declared the application to be a general rate case, suspended the proposed rates, required public notice and scheduled hearings.

On June 24, 1993, the Applicant prefiled the testimony of William E. Grantmyre, President of Heater Utilities, Inc., and Freda Hilburn, Director of Rates, in support of its application.

On July 27, 1993, the Public Staff prefiled the testimony of Kenneth E. Rudder, Utilities Engineer, Water Division; Pamela A. Britt, Staff Accountant, Accounting Division; and the joint testimony of Mary Elise Cox, Assistant Director, Accounting Division, and Andy R. Lee, Director, Water Division, reporting the findings of the Public Staff audit and investigation.

Public notice was given to the customers as evidenced by the Certificate of Service filed by the Applicant on May 5, 1993.

On August 3, 1993, the customer hearing was held as scheduled and seven customers testified.

Two customers from Mallards Crossing Subdivision, Wayne C. Maxwell and Richard Fisher, testified in opposition to the proposed rates. Richard May, Vice President of Stonebridge Homeowners Association, testified regarding pressure problems and water shortage on the weekend of June 19 and 20, 1993. William Moore, from West Oaks Subdivision, testified regarding occasional discolored water or sediment in water. Three customers from Thompson Mill Subdivision testified: Ernie Sherrill, President of the Homeowners Association; James Rivers and Tommy Lloyd. In addition, they introduced a petition requesting assurances regarding the quantity and quality of water supply to Thompson Mill Subdivision. The testimony from Thompson Mill Subdivision primarily regarded a water shortage on the weekend of June 26 and 27, 1993. James Rivers also testified to discolored water.

On August 13, 1993, the Applicant filed a report addressing concerns expressed in the testimony of Public Staff witness Rudder and the service concerns testified to at the August 3, 1993, customer hearing.

On August 16, 1993, the Applicant and Public Staff filed a Joint Stipulation regarding the revenue requirement and rates.

The hearing was held as scheduled on August 17, 1993, and two customers appeared to testify: John Houck of Meadow Ridge, complained of discolored water, and William Dix of Sheffield Manor, protested the amount of the rate increase. The Commission accepted the filed stipulation by the Applicant and Public Staff. The Applicant presented the pre-filed accounting testimony of Freda Hilburn and the testimony of Jerry Tweed and William E. Grantmyre regarding service issues. The prefiled testimony of the Public Staff was accepted into the record as if given orally from the stand.

Based on the information contained in the Commission files, the verified application, the testimony, the stipulations, and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. Heater Utilities, Inc., is a public utility as defined by G.S. 62-3(23) and, as such, is subject to the jurisdiction of and regulation by the North Carolina Utilities Commission. Heater is lawfully before the Commission seeking an increase in rates and charges pursuant to G.S. 62-133.

2. The Applicant's monthly present rates, proposed rates, and rates stipulated to by the Applicant and Public Staff are as follows:

Base charge, zero usage - Meter Size	Present	Proposed	Stipulated
<1"	$ 8.28	$ 9.90	$ 9.61
1"	20.70	24.75	24.03
1.5"	41.40	49.50	48.05
2"	66.24	79.20	76.88
3"	124.20	148.50	144.15
4"	207.00	247.50	240.25
6"	414.00	495.00	480.50
Usage Charge (per 1,000 gallons)	2.35	2.83	2.84

3. The Applicant's overall level of service is adequate.

4. The Public Staff has conducted a complete investigation of Heater's rate base, reasonable operating revenue deductions, and operating revenues.

5. The Public Staff and Heater have stipulated that, based on the Public Staff's investigation, a revenue requirement of $3,446,402 is just and reasonable to provide a reasonable return to Heater. Under Heater's currently approved rates, the Company is receiving $2,896,402 in pro forma total operating revenues.

6. The test period established for use in this proceeding is the 12 months ended December 31, 1992.

7. The revenues from its water utility operations that the Applicant should have the opportunity to generate under the rates agreed to by the Applicant and Public Staff are $3,446,402 consisting of $3,436,267 from water service revenues and $18,048 from other revenues less $7,913 of uncollectibles.

8. The Applicant and Public Staff support uniform rates in this proceeding primarily due to geographical location of Heater's systems and economic and operational considerations. No customers or any other party testified in support of system-specific rates.

9. The rates agreed to by the Public Staff and Applicant are reasonable and should be approved.

10. The rates contained in Appendix A, attached hereto, will allow the Applicant to generate the revenue requirement approved herein.

EVIDENCE AND CONCLUSIONS

Based upon the entire record of this proceeding, the Commission is of the opinion that the rates agreed to Heater and the Public Staff are reasonable and should be approved.

The Commission is of the opinion that service problems are being adequately addressed. The Company plans to provide additional water supplies to both Stonebridge and Thompson Mill Subdivisions. The service report indicates the water quality in West Oaks, Meadow Ridge, and Thompson Mill Subdivisions is within established EPA guidelines but the Company is and will continue to take steps to improve the water quality through improved flushing and treatment of wells.

The Company has agreed to file a report within 90 days of this Order to address the systems currently having less than the minimum well yield. This report is to include, but not be limited to, the Company's plans for addressing the situation by system; for any systems where prompt action is not planned, the reason the Company considers the yield to be satisfactory; and any plans of the Company to connect any additional subdivisions to the master systems. The Company has further agreed to file a report on the status of planned improvements in Thompson Mill, West Oaks, Meadow Ridge, and Hollybrook Subdivisions, also within the above 90 days and again at the end of one year.

Following is a summary of the agreed upon capital structure, rates of return, revenue and expense data, and rate base:

Capital Structure and Related Cost

	Capitalization Rate	Original Cost Rate Base	Embedded Cost	Net Operating Income
Debt	50.18%	$2,866,164	7.91%	$226,714
Preferred Stock	4.59%	262,170	7.68%	20,135
Equity	45.23%	2,583,432	10.77%	278,114
Total	100.00%	$5,711,766		$524,963

Overall Rate of Return - 9.19%

Operating Income

Operating Revenue	$3,446,402
Operating Revenue Deductions	2,921,439
Net Operating Income for Return	$ 524,963

Original Cost Rate Base

Plant in Service	$6,908,464
Customer Deposits	(19,752)
Accumulated Deferred Income Taxes	(157,317)
Accumulated Depreciation	(1,532,335)
Net Water Plant in Service	$5,199,060
Working Capital Allowance	323,641
Meters and Supplies Inventory	190,347
Cost Free Capital	(1,282)
Original Cost Rate Base	$5,711,766

It is noted that, by the terms of the Joint Stipulation, the above figures include the costs of only one SOC test per entry point. In the event that the Company is required to do additional tests per entry point, the Company is free to apply for a pass-through of the costs for any additional tests per entry point.

The Joint Stipulation also specifies that Heater will, within 60 days of this Order, file an updated gross-up factor related to contributions-in-aid-of-construction (CIAC) based upon the capital structure and cost rates found reasonable in this docket.

Approval of the Joint Stipulation shall have no precedential value in future proceedings for Heater or any other public utility regulated by the North Carolina Utilities Commission, particularly with reference to the recovery of SOC test costs.

IT IS, THEREFORE, ORDERED as follows:

1. That the Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138. Said Schedule of Rates is hereby authorized to become effective for service rendered on and after the date of this Order.

2. That a copy of the Notice to the Customers, attached hereto as Appendix B, shall be mailed or hand delivered to all affected customers by the Applicant in conjunction with the next regularly scheduled billing process.

3. That Heater shall within 90 days file a report with this Commission to address the systems currently having less than the minimum well yield. This report is to include, but not be limited to, the Company's plans for addressing the situation by system; for any systems where prompt action is not planned, the reason the Company considers the yield to be satisfactory; and any plans of the Company to connect any additional subdivisions to the master systems. The Company shall further file a report on the status of its planned improvements in Thompson Mill, West Oaks, Meadow Ridge and Hollybrook Subdivisions, also within 90 days and again at the end of one year.

4. That Heater shall, within 60 days of this Order, file an updated gross-up factor related to CIAC based upon the capital structure and cost rates found reasonable in this docket.

5. That this docket shall remain open for a period of no less than 120 days after the date of this Order for the filing of the reports required above and any response generated by these reports.

6. That the Joint Stipulation filed in this docket by Heater and the Public Staff on August 16, 1993, be, and the same is hereby, approved; provided, however, that such approval shall have no precedential value in future proceedings for Heater or any other public utility regulated by the North Carolina Utilities Commission, particularly with reference to the recovery of SOC test costs.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of August 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

DOCKET NO. W-274, SUB 75
SCHEDULE OF RATES
FOR
HEATER UTILITIES, INC.

for providing water utility service in
all of its service areas in North Carolina

Metered Rates: (monthly)

Base monthly charge for zero consumption

<1" meter	$ 9.61
1" meter	24.03
1 1/2" meter	48.05
2" meter	76.88
3" meter	144.15
4" meter	240.25
6" meter	480.50

Commodity charge - $2.84 per 1,000 gallons
($2.13 per 100 cubic feet)

Temporary Service: $40.00 - A one-time charge to builder of a residence under construction payable in advance. Fee entitles builder to six months service, unless construction is completed earlier and the service is intended for only normal construction needs for water (not irrigation). The charge is applicable only in the seven following subdivisions where such charge is specifically provided by contract with the developer as follows:

Chesterfield II	- Contract date August 24, 1988
Fairstone	- Contract date September 3, 1988
Fox N' Hound	- Contract date June 13, 1988
Pear Meadow	- Contract date January 19, 1988
Pebble Stone	- Contract date August 24, 1988
Southwoods Sect. III	- Contract date May 25, 1988
South Hills Ext.	- Contract date May 25, 1988

* Connection Charges: 3/4" x 5/8" meters

For taps made to existing mains installed inside franchised service area: $525.00

For mains extended by Heater outside of franchised service area: 120% of the actual cost of main extension

* Connection Charges: Meters exceeding 3/4" x 5/8"

For all taps: 120% of actual cost

* Meter Installation Fee:

Where cost of meter installation is not otherwise recovered through connection charges $70.00

Reconnection Charges:

If water service cut off by utility for good cause:	$20.00
If water service discontinued at customer's request:	$ 5.00

Returned Check Charge: $10.00

Bills Due: On billing date

Bills Past Due: 15 days after billing date

Billing Frequency: Shall be monthly for service in arrears

Finance Charges for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

* In most areas, connection charges do not apply pursuant to contract and only the $70.00 meter installation fee will be charged to the first person requesting service (generally the builder). Where Heater must make a tap to an existing main, the charge will be $525.00, and where main extension is required, the charge will be 120% of the actual cost.

Issued in accordance with authority granted by the North Carolina Utilities Commission in Docket No. W-274, Sub 75, on this the 18th day of August 1993.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-274, SUB 75

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina 27519, for Authority to Increase Rates for Water Utility Service in All Its Service Areas in North Carolina	) NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued on Order authorizing Heater Utilities, Inc., to charge increased rates for water service to all of its water customers in North Carolina. The new approved rates are as follows:

WATER AND SEWER - RATES

Base Monthly Charge for Zero Usage:

Meter Size	Base Charge
<1"	$ 9.61
1"	24.03
1.5"	48.05
2"	76.88
3"	144.15
4"	240.25
6"	480.50

Commodity Charge - $2.84 per 1,000 gallons ($2.13 per 100 cubic feet)

The new rates will increase the average residential bill from $23.04 to $27.45, based on an average monthly usage of 6,280 gallons.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of August 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-720, SUB 119

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Mid South Water Systems, Inc., Post Office Box 127, Sherrills Ford, North Carolina 28673, for Authority to Increase Rates for Sewer Utility Service in All Its Service Areas in North Carolina) ORDER APPROVING PARTIAL RATE INCREASE

HEARD IN: Civil Courtroom No. 3, Iredell County Hall of Justice, Water Street, Statesville, North Carolina, on October 20, 1992, at 7:00 p.m., and Room 118, Charlotte-Mecklenburg Government Center, 600 E. Fourth Street, Charlotte, North Carolina, on October 21, 1992, at 7:00 p.m., and Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on November 12, 1992, at 9:30 a.m.

BEFORE: Commissioner Charles H. Hughes, Presiding, Chairman William W. Redman, Jr., and Commissioners Sarah Lindsay Tate, J.A."Chip" Wright, Robert O. Wells, Laurence A. Cobb, and Allyson K. Duncan

Appearances:

For the Applicant:

Robert F. Page, Attorney at Law, Crisp, Davis, Schwentker, Page, Currin and Nichols, 4011 Westchase Blvd., Suite 400, Raleigh, North Carolina 27607

For the Public Staff:

Robert B. Cauthen, Jr., Staff Attorney, Public Staff, North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

For the Attorney General:

Karen E. Long, Assistant Attorney General, Lorinzo L. Joyner, Special Deputy Attorney General, and Margaret Force, Associate Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On June 30, 1992, Mid South Water Systems, Inc., (Mid South or the Applicant) filed an application for a general rate increase for sewer utility service. By Order issued on July 28, 1992, the Commission declared the application to be a general rate case, suspended the proposed rates, required public notice and scheduled hearings.

The Public Staff, on August 25, 1992, filed a data request to conduct a field investigation in response to the Applicant's application.

On September 10, 1992, the Attorney General filed a Notice of Intervention.

The Applicant, on September 11, 1992, filed a Notice of Appearance of Counsel and a Motion for Extension of Time to Prefile Testimony. On September 23, 1992, the Commission issued an Order extending the date for the filing of prefiled testimony.

On September 28, 1992, the Applicant filed the prefiled testimony of Jocelyn Perkerson, Vice President of Finance and Regulatory Affairs, in support of its application.

On October 20, 1992, a public hearing was conducted in Statesville, North Carolina, where the testimony of twelve of the Applicant's customers was heard.

On October 21, 1992, a public hearing was conducted in Charlotte, North Carolina, where the testimony of eight of the Applicant's customers was heard.

On October 23, 1992, the Public Staff filed the testimony of its engineer and accountant, giving the results of their analysis of Mid South's sewer rate application and proposed rates. On that same date, the Public Staff filed the Notice of Affidavit and Affidavit of its financial analyst.

On November 12, 1992, the Applicant and Public Staff filed a Joint Stipulation regarding the overall revenue requirement and level of rates for use in this proceeding. Also, on November 12, 1992, the Applicant filed rebuttal testimony of Thomas Carroll Weber, President, Mid South Water Systems, Inc.

A hearing was held in Raleigh, North Carolina, on November 12, 1992, to receive testimony and exhibits from the Applicant, the Public Staff and any other party of record.

At the request of the Commission and the Attorney General, on December 7, 1992, the Applicant late-filed two exhibits: (1) Work Orders and Complaint Forms and (2) Trouble Report Log Sheets. The Applicant subsequently filed, as other late-filed exhibits, its organizational chart and a customer service manual.

On February 24, 1993, Carolina Water Service, Inc. of North Carolina filed a Motion for leave to file comments as amicus curiae in support of the position taken by Mid South with respect to gain on the sale of the Autumn Chase Subdivision system.

Based on the information contained in the Commission files, the verified application, the exhibits, testimonies and stipulations and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. Mid South Water Systems, Inc., is a public utility as defined by G.S. 62-3(23) and, as such, is subject to the jurisdiction and regulation of the North Carolina Utilities Commission. Mid South is lawfully before the Commission seeking an increase in rates and charges pursuant to G.S. 62-133.

2. The Applicant's monthly present rates, proposed rates and rates stipulated to by the Applicant and Public Staff are as follows:

Commercial (Metered rates)

	Present	Proposed	Stipulated
Base charge, zero usage	$ 8.00	$20.00	$12.25
Usage Charge per 1,000 gallons	$ 2.50	$ 3.00	$ 3.00
Residential (Flat rate monthly charge)	$24.00	$34.10	$29.00

3. The overall service quality is adequate. The Company has taken steps to resolve consumer complaints, including matters testified about by the consumer witnesses in this case.

4. The Public Staff has conducted a complete investigation of Mid South's rate base, reasonable operating revenue deductions, and operating revenues.

5. The Public Staff and Mid South have stipulated that, based on the Public Staff's investigation, a revenue requirement of $424,648 is just and reasonable and provides a reasonable return to Mid South on its operations.

6. The test period established for use in this proceeding is the 12 months ended April 30, 1992.

7. The revenues that the Applicant should have the opportunity to generate under the rates agreed to by the Applicant and Public Staff for sewer utility service are $424,648, consisting of $11,119 from metered revenues, $412,032 in flat revenues and $1,497 from other revenues.

8. The rates agreed to by the Public Staff and Applicant are reasonable and should be approved.

9. The rates contained in Appendix A, attached hereto, will allow Mid South the opportunity to achieve the reasonable revenue requirement as determined herein.

10. The Stipulation entered into in this docket provides that both the Public Staff and Mid South recognize and agree that the Stipulation has no precedential value and shall not be cited or relied upon by either party in any future proceeding.

11. The accounting and ratemaking treatment in this docket, with respect to the disposition of the gain on the sale of the Autumn Chase Subdivision system, has no precedential value and shall not be cited and relied upon in any future proceeding before the Commission.

12. Mid South has filed in this docket a "Customer Relations Manual".

13. A formal investigation of Mid South's CIAC obligations in the manner recommended by the Attorney General is not warranted at this time.

EVIDENCE AND CONCLUSIONS

Based upon the entire record of this proceeding, the Commission is of the opinion that the rates agreed to by the parties to this proceeding are reasonable and should be approved.

The Commission is of the opinion, and thus concludes, that service problems are being adequately addressed and that the Joint Stipulation of Mid South and the Public Staff should be adopted by the Commission. Mid South agrees to accept the rate design recommended by the Public Staff; however, this rate design does not establish a binding precedent for any future adjustments. Further, the Commission concludes that, as a stipulated case, none of the accounting and expense adjustments proposed by either party, including the treatment of the gain on the sale of the Autumn Chase Subdivision system, are adopted as precedent. Instead, the parties hereto have merely agreed to a stipulated revenue requirement and the rates necessary to achieve that revenue requirement. In future rate cases, both parties may argue or advocate the same or different positions on any cost of service or revenue issue. In testimony and exhibits filed by the Public Staff on February 10, 1993, in Docket No. W-274, Subs 71 and 72, involving Heater Utilities, Inc., reference is made to the disposition of the gain on sale involved in this proceeding. Accordingly, the Commission concludes that such reference to the Stipulation in this docket shall not be considered or relied upon by the Commission in its consideration of the Heater Utilities, Inc., proceeding cited above.

Following is a summary of the agreed to margin, revenue and expense data under approved rates, and rate base:

Margin on Operating Revenue Deductions - 9.9%

Operating Income

Operating Revenue	$424,648
Operating Revenue Deductions	-389,592
Net Operating Income for Return	$ 35,056

Rate Base

Plant in Service	$157,553
Accumulated Depreciation	(31,219)
Net Sewer Plant in Service	126,334
Cash Working Capital	40,691
Average Tax Accruals	(6726)
Rate Base	$160,299

The Attorney General, in his Brief, states that he believes that Mid South has demonstrated its commitment to meeting customer service needs by its new customer service procedures. It was recommended by the Attorney General that Mid South be required to file certain reports with a copy of the completed logs and a statement of the Company's monitoring efforts with respect to its new customer service procedures. The management of Mid South has indicated that it will monitor its customer service under the new procedures which have been implemented. The Commission is not persuaded that any reporting requirements are necessary at this time; however, the Commission fully expects Mid South's management to monitor fully its commitment to its newly implemented customer service procedures.

With respect to the recommendation of Attorney General that an investigation be instituted regarding Mid South's CIAC obligation, the Commission recognizes that the 1992 Annual Report of Mid South is due to be filed in the near future. Also, certain financial information has been requested by the Commission with respect to the application pending relating to the Forsyth Water Company, Inc., proceeding in Docket No. W-1027. Accordingly, the Commission is of the opinion that an investigation, as suggested by the Attorney General, is not warranted at this time.

IT IS, THEREFORE, ORDERED as follows:

1. That the Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138. Said Schedule of Rates is hereby authorized to become effective for service rendered on and after the date of this Order.

2. That a copy of the Notice to the Customers, attached hereto as Appendix B, shall be mailed or hand delivered to all affected customers by the Applicant in conjunction with the next regularly scheduled billing process.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

SCHEDULE OF RATES
FOR
MID SOUTH WATER SYSTEMS, INC.

for providing sewer utility service in
all of its service areas in North Carolina

METERED SERVICE (Commercial)

Base charge (no usage)	$ 12.25
Usage charge (per 1000 gals)	$ 3.00

FLAT RATE SERVICE (Residential)

Monthly Charge	$ 29.00

TAP ON FEES:

Except where excluded by contract	$400.00

RECONNECTION FEES:

If service cut off at customers request or by the utility for good cause and the sewer customer is also a water customer	$ 15.00
If water service is not provided by the utility	$ 75.00

Customers who have been disconnected and are reconnected at the same address within nine months of disconnection will be charged the monthly base charge or the monthly flat rate per month for the period during which they were disconnected.

RETURNED CHECK CHARGE: $20.00

BILLS DUE: On billing date

BILLS PAST DUE: 20 days after billing date

BILLING FREQUENCY:
Monthly for service in areas

FINANCE CHARGE FOR LATE PAYMENT:
1% per month on unpaid balance of bills still past due 25 days after billing date.

DEPOSITS:
May be requested in accordance with NCUC Rules R12-1 through R12-6.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-720, Sub 119, on this the 24th day of March 1993.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-720, SUB 119

In the Matter of		
Application by Mid South Water Systems, Inc., P.O. Box 127, Sherrills Ford, North Carolina 28673, for Authority to Increase Rates for Sewer Utility Service in All Its Service Areas in North Carolina	)	NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission issued an Order on March 24, 1993, approving a partial increase in sewer rates and charges for Mid South Water Systems, Inc. (Mid South). By application filed on June 30, 1992, Mid South requested an increase in its rates and charges for sewer utility service of approximately 42%. The Public Staff contended that the level of increase sought by Mid South was excessive. On November 12, 1992, the Public Staff and Mid South filed a joint stipulation agreeing to the rates which should be allowed in this proceeding.

Following public hearings in Statesville, Charlotte and Raleigh, the Commission concluded that Mid South should be allowed to increase its sewer rates, but not to the level originally requested by Mid South. The Company's existing rates, proposed rates, and rates approved by the Commission pursuant to the stipulation between Mid South and the Public Staff are shown below.

	Existing Rates	Rates as Proposed By Mid South	Rates Approved by the Commission
Commercial -			
Base Charge, zero usage	$ 8.00	$20.00	$12.25
Usage charge per 1,000 gallons	$ 2.50	$ 3.00	$ 3.00
Residential -			
Flat rate monthly charge	$24.00	$34.10	$29.00

The new rates will become effective for service rendered on and after the date of this notice.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-778, SUB 17

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by CWS Systems, Inc., 5701 Westpark Drive, Suite 101, Charlotte, North Carolina 28224, for Authority to Increase Rates for Water Utility Service in Amber Acres North, Ashley Hills North, Country Crossing, Jordan Woods, Neuse Woods, Oakes Plantation, Sandy Trails, Stewart's Ridge, and Tuckahoe Subdivisions in Wake County, Heather Glen Subdivision in Durham County, Wilder's Village Subdivision in Franklin County, and Ransdell Forest Subdivision in Nash County	)	FINAL ORDER APPROVING PARTIAL INCREASE IN RATES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, August 31, 1993, at 7:00 p.m.

BEFORE: Commissioner Allyson K. Duncan, presiding, and Commissioners Laurence A. Cobb and Ralph A. Hunt

APPEARANCES:

For the Applicant:

Edward S. Finley, Jr., Hunton & Williams, Attorneys at Law, Post Office Box 109, Raleigh, North Carolina 27602

For the Public Staff:

Vickie L. Moir, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On April 12, 1993, CWS Systems, Inc. (Applicant, Company, or CWS Systems), filed an application with the Commission for authority to increase its rates for providing water utility service in the above-captioned service areas in North Carolina.

On April 21, 1993, the Public Staff filed a copy of its letter to the Company requesting that certain information which had been omitted from the W-I filing be provided and suggesting a procedure to accommodate the Company's desire that this information be kept confidential. On May 7, 1993, the Company filed a proposed order negotiated between the Public Staff and the Company incorporating an agreement between those two parties concerning certain information which the Company desired to be treated as confidential. At the same time, the Company filed as confidential its responses to Items 3, 16, and 17 of the W-1 filing requirements. The Commission issued a Protective Order on May 26, 1993.

On May 5, 1993, the Commission issued an Order declaring the matter a general rate case, suspending the proposed rates, setting hearings, establishing dates for providing updates and filing testimony, and requiring public notice. That Order provided for a separate hearing to receive testimony from residents of Stewart's Ridge Subdivision. The Company had requested authority to recover the cost of bottled water provided to the residents in Stewart's Ridge Subdivison.

On May 24, 1993, the Company filed a letter withdrawing its request for the recovery of the cost of bottled water, requesting that the hearing scheduled to receive the testimony of Stewart's Ridge Subdivision residents be canceled, and requesting that the Company be relieved of the requirement of giving notice of that hearing. The Company indicated that an alternative water supply (a new well) may soon become available for Stewart's Ridge Subdivision. The Public Staff filed a letter on May 25, 1993, indicating that the Public Staff did not object to the Company's proposal to cancel the hearing and reschedule the hearing if necessary. On May 28, 1993, the Commission issued an Order canceling the hearing.

On June 10, 1993, the Company filed the certificate of service indicating that public notice had been given as required.

On June 24, 1993, the Company filed an update of its accounting information and information and proposal regarding the pass through of S.O.C. testing costs.

On July 2, 1993, the Company prefiled the testimony of Carl Daniel and Mark F. Kramer.

On July 28, 1993, the Public Staff prefiled the testimony of Ronald D. Brown, Utilities Engineer, Water Division, and Darlene P. Peedin, Staff Accountant, Accounting Division, and the Notice of Affidavit and Affidavit of John R. Hinton, Financial Analyst, Economic Division, Public Staff.

On August 26, 1993, the Stipulation of CWS Systems, Inc., and the Public Staff was filed with the Commission.

The matter came on for hearing at the time and place shown above. The following customers appeared and testified: Barbara Blalock, Polly Kelly, Harry Cadman, James Winegar, Mike Peters, Judy Harris, Patty Kreiselman, Craig Hales, Margie Mitchell, and L. E. Robinson.

Carl Daniel, Vice President of Operations of CWS Systems, testified on behalf of the Company. Mr. Daniel addressed problems and concerns testified to by the customers. He indicated that the Company would follow up with every customer who testified at the hearing and voiced a complaint and that the Company would file a report with the Commission regarding what was found and what action was taken. That report was filed on September 15, 1993.

The Public Staff presented the testimony of Dennis Boyer, an Environmental Engineer with the Division of Environmental Health (DEH), and Ronald Brown, a Utilities Engineer with the Public Staff's Water Division. Mr. Boyer testified regarding the progress and status of the improvements in Stewart's Ridge Subdivision. Mr. Brown testified to upgrades and improvements made by the Company in all of the CWS Systems' subdivisions involved in this proceeding and recommended that the Company provide reports of responses to customers' testimony to the Commission within 30 days.

The Commission accepted the Stipulation of the Applicant and the Public Staff and it was admitted into evidence.

Based on the information contained in the Commission files, the verified application, the testimony, the Stipulation, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. CWS Systems, Inc., is a public utility as defined by G.S. 62-3(23) and is subject to regulation by the North Carolina Utilities Commission. CWS Systems is lawfully before the Commission seeking an increase in rates and charges pursuant to G.S. 62-133.

2. The Applicant is providing adequate water utility service in all the subdivisions included in this proceeding.

3. The Applicant's monthly present rates, the Applicant's proposed monthly rates, and the rates stipulated to by the Applicant and Public Staff, are as follows:

Residential

	Present	Proposed	Stipulated
Base Facility charge	$ 6.00	$ 9.00	$ 8.85
Usage charge (per 1000 gal.)	1.49	2.60	2.50
Flat Rate Service	14.10	25.00	25.00

Commercial

	Present	Proposed	Stipulated
Base Facility charge			
5/8" X 3/4" meter	-	$ 9.00	$ 8.85
1" meter	-	22.50	22.13
1 1/2" meter	-	45.00	44.25
2" meter	-	72.00	70.80
3" meter	-	135.00	132.75
4" meter	-	225.00	221.25
6" meter	-	450.00	442.50
Usage Charge (per 1000 gal.)	-	2.60	2.50
Flat Rate Service (per single family equivalent)	-	$ 20.00	$ 25.00

4. The test period appropriate for use in this proceeding is the 12 months ended December 31, 1992.

5. The annual revenues from its water utility operations that the Applicant should have the opportunity to generate under the rates agreed to by the Applicant and Public Staff are $213,940, consisting of $208,436 from water service revenues and $5,837 from other revenues, less $333 of uncollectibles.

6. The annualized level of reasonable and appropriate operating revenue deductions requiring a return is $178,834. This amount includes annual depreciation of $6,564.

7. The water rates approved produce a margin in operating revenue deductions of 8.9766%, which is just and reasonable for use in this proceeding and represents an increase of $75,732.

8. The rates agreed to by the Public Staff and Applicant, as represented in the Stipulation of CWS Systems, Inc., and the Public Staff, filed August 26, 1993, are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting Finding of Fact No. 1 is contained in the verified application of the Company and is not contested by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting Finding of Fact No. 2 is contained in the verified application of the Company, the testimony of the public witnesses, the testimony of Company witness Carl Daniel, the customer follow-up report filed by the Company after the hearing, and the testimony of Public Staff witnesses Dennis Boyer and Ronald Brown.

Ten public witnesses appeared and testified at the public hearing. Barbara Blalock of the Neuse Woods Subdivision was concerned about the amount of the proposed increase, spots on her silverware, and discolored water. She stated that the Company did not notify customers in Neuse Woods Subdivision about interruptions in service. Polly Kelley, also of Neuse Woods Subdivision, testified that rust and other sediment was in her water, and that the Company had not turned off water caused by a leak in a neighborhood mobile home. Margie Mitchell of Neuse Woods Subdivision agreed with the statements of Ms. Blalock, noted fixture staining in her home, and requested that the water be tested.

Harry Cadman of Country Crossings Subdivision expressed concern about the rate increase and the possible presence of metals in his water. Mr. Cadman stated that he was told by another company that tested his water that the water was acidic and was damaging his home's copper plumbing, causing stains and the presence of copper. Mr. Cadman also described metallic taste and the presence of sediment.

James Winegar of Stewart's Ridge Subdivision appeared and stated that he was opposed to the amount of the proposed increase, that he believed the water was not fit to drink because of DEH warnings, and that CWS Systems had an unfair economic advantage over companies that complied with water quality regulations. Mr. Winegar also testified that he now receives home-delivered bottled water, paid for by the Applicant.

Mike Peters, a representative of the Heather Glen Homeowners Association, stated that he thought the proposed rate increase was too high, and that he believed there were quality problems, including sediments and low pressure. Judy Harris, also of Heather Glen Subdivision, testified that there were black sediments in her water, which required cleaning cold water lines. Patty Kreiselman, another Heather Glen Subdivision resident, stated that leaks were slow to be repaired, and that there was low water pressure in her home and stains to her appliances and plumbing fixtures caused by sediments and chemicals.

Craig Hales, of the Jordan Woods Subdivision, complained primarily about the amount of the proposed rate increase, but also expressed concern about discoloration and the safety of his water.

L.E. Robinson of Sandy Trails Subdivision complained of sedimentation, low water pressure, a slimy feel, fluctuating pH, and a periodic chlorine odor.

In responding to the comments from Public Witnesses from the Heather Glen Subdivision, Company witness Daniel testified that the Company has taken steps to resolve the presence of sediments, or manganese, in the water there, including the installation of blowoffs, the commencement of a flushing program, the construction of an additional well, and the addition of a sequestering agent to tie up iron or manganese. He testified that these efforts had improved water quality in the subdivision, and that the Company will take additional measures, if necessary, to resolve manganese complaints.

In response to comments about fluctuating pH in the Sandy Trails Subdivision, Mr. Daniel testified that the company maintains pH levels in the subdivision with caustic soda. The Company's monitoring of pH levels in Sandy Trails Subdivision shows compliance with state and federal standards.

Mr. Daniel also addressed radium and DEH warnings in Stewart's Ridge Subdivision. He indicated that radium in the water existed at the time the Company purchased the system. Since then, CWS Systems has worked with the DEH to resolve the problem. The Company has acquired land and drilled a new well that is currently operable. Pending final approval of this new water supply by the DEH, the Company will continue to supply customers in Stewart's Ridge Subdivision with bottled water.

At the hearing, Mr. Daniel testified that he was not prepared to address specifically some of the other concerns raised by customers at the hearing, but that CWS Systems staff would follow up the concerns expressed by each customer at the meeting. As a result, after the August 31 hearing, CWS Systems' representatives (1) visually checked water from an outside faucet at the home of witness Craig Hales of Jordan Woods Subdivision, finding no sediment, (2) investigated outages at Neuse Woods Subdivision and determined that past service interruptions were caused by vandalism to electric meters and a scheduled water outage, (3) determined that CWS Systems staff had responded to a leak the same day it was reported <u>inside</u> a mobile home at Neuse Woods Subdivision previously condemned by the Wake County Health Department, but that witness Polly Kelly had cut the water off before the Company's arrival, (3) confirmed that pH levels at the home of L.E. Robinson in Sandy Trails were within DEH guidelines, and increased Mr. Robinson's water pressure, (4) determined that pH levels at the home of Harry Cadman of Country Crossings Subdivision were within DEH limits, (5) increased water pressure at the home of Patty Kreiselman in Heather Glen Subdivision, (6) provided Margie Mitchell of Neuse Woods Subdivision with copies of inorganic, THM, and bacteriological test results, and (7) informed James Winegar of Stewart's Ridge Subdivision of the company's efforts to correct the radium problem in that subdivision. Moreover, between September 1 and September 3, 1993, the Company left door tags at the homes of six homes of witness-customers not at home when Company representatives arrived. The tags requested the customer to call the Company's office to schedule an appointment. As of September 10, 1993, none of the customers who received a door tag had contacted the Company.

Finally, at the August 31 hearing, Public Staff witness Boyer testified that the Company had devised a good solution to the natural radium contamination problem in the water supply at Stewart's Ridge Subdivision. Mr. Boyer also indicated that he expected a well constructed by the Company at Stewart's Ridge Subdivision to be approved soon and for DEH to rescind its warning letter regarding water quality at Stewart's Ridge. Mr. Brown testified that, since purchasing the systems less than two years ago, the Company had improved the physical condition of the well houses, plumbing, and other equipment inside the well houses in all of the subdivisions. Mr. Brown also testified that the Company kept chemical tanks filled and maintained sheets inside the well-houses that indicated regular visits and maintenance by operators.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACTS NOS. 3 THROUGH 8

The evidence supporting Findings of Fact Nos. 3 through 8 is contained in the August 26, 1993, Joint Stipulation entered into between the Company and the Public Staff, in the Company's verified application, and in the testimony provided by the Company and by the Public Staff. Based upon the entire record of this proceeding, the Commission accepts the Joint Stipulation of the Company and the Public Staff. The rates agreed to by the Company and the Public Staff therein are just and reasonable and should be approved.

As stated by the Company and the Public Staff in the Joint Stipulation filed in this proceeding, the agreements reached do not necessarily reflect the respective parties' beliefs as to the proper treatment or level of the matters cited. The Commission concurs in the parties' agreements that, except as needed to carry out the terms of this Order, none of the positions, treatments, figures, or other matters reflected in this stipulation shall have any precedential value, nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matter in issue.

IT IS, THEREFORE, ORDERED as follows:

1. That the Schedule of Rates, attached hereto as Appendix A, are the rates that have been approved by the Commission and are deemed to be filed with the Commission pursuant to G.S. 62-138.

2. That a copy of the Notice to the Customers, attached hereto as Appendix B, shall be mailed or hand delivered to all affected customers by the Applicant in conjunction with the next regularly scheduled billing process.

3. That the Joint Stipulation filed in this docket by CWS Systems, Inc., and the Public Staff on August 26, 1993, is adopted by reference in this Order by the Commission, with the understanding that none of the provisions, treatments, figures, or other matters reflected in the Joint Stipulation shall have any precedential value, nor shall they be used in any subsequent proceedings before this Commission as proof of the matters at issue.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

SCHEDULE OF RATES
for
CWS SYSTEMS, INC.
for providing water service in

Amber Acres North, Asley Hills North, Country Crossing, Jordan Woods, Neuse Woods, Oakes Plantation, Sandy Trails, Stewart's Ridge, and Tuck-A-Hoe Subdivisions in Wake County; Heather Glen Subdivision in Durham County; Wilders Village Subdivision in Franklin County; and Ransdell Forest Subdivision in Nash County

Metered Water Rates:

Base Facility Charges			
A.	Single family residence		$ 8.85
B.	Where service is provided through a master meter and each dwelling unit is billed individually (per unit)		$ 8.85
C.	Where service is provided through a master meter and a single bill is rendered for the master meter (per unit)		$ 7.85
D.	Commercial and other (Based on meter size):	5/8" x 3/4" meter	$ 8.85
		1" meter	$ 22.13
		1/2" meter	$ 44.25
		2" meter	$ 70.80
		3" meter	$132.75
		4" meter	$221.25
		6" meter	$442.50
	Usage charge per 1,000 gallons		$ 2.50

WATER AND SEWER - RATES

Flat Rate Service:

A.	Single family residential	$ 25.00
B.	Commercial (per single family equivalent)	$ 25.00

Connection Charge:

A. 5/8" $500.00 + gross up

B. Meter larger than 5/8" - actual cost of meter and installation

Meter Testing Fee: $ 20.00

New Water Customer Charge: $ 27.00

Reconnection Charge:

A.	If water service is cut off by the utility for good cause	$ 27.00
B.	If water is disconnected at the customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base facility charge for the service period they were disconnected).

Bills Due: On billing date

Bills Past Due: 15 days after billing date

Billing Frequency: Shall be bimonthly for service in arrears

Finance Charge for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in accordance with authority granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 17 on this the 22nd day of September 1993.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 17

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by CWS Systems, Inc., 5701 Westpark Drive, Suite 101, Charlotte, North Carolina 28224 for Authority to Increase Rates for Water Utility Service in Amber Acres North, Asley Hills North, Country Crossing, Jordan Woods, Neuse Woods, Oakes Plantation, Sandy Trails, Stewart's Ridge, and Tuck-A-Hoe Subdivisions in Wake County; Heather Glen Subdivision in Durham County; Wilders Village Subdivision in Franklin County; and Ransdell Forest Subdivision in Nash County	NOTICE TO CUSTOMERS

BY THE COMMISSION: Notice is hereby given that the North Carolina Utilities Commission has issued a Final Order, approving a partial increase in water rates to CWS Systems, Inc. (Applicant) for water utility service provided in the above-captioned service areas.

This decision follows an investigation by the Public Staff and a public hearing held in Raleigh, North Carolina, on August 31, 1993. The Public Staff and the Applicant have stipulated to the following rates:

<u>Metered Water Rates:</u>

Base Facility Charges

A.	Single family residence	\$ 8.85
B.	Where service is provided through a master meter and each dwelling unit is billed individually (per unit)	\$ 8.85
C.	Where service is provided through a master meter and a single bill is rendered for the master meter (per unit)	\$ 7.85
D.	Commercial and other (Based on meter size): 5/8" x 3/4" meter	\$ 8.85
	1" meter	\$ 22.13
	1/2" meter	\$ 44.25
	2" meter	\$ 70.80
	3" meter	\$132.75
	4" meter	\$221.25
	6" meter	\$442.50
	Usage charge per 1,000 gallons	\$ 2.50

<u>Flat Rate Service:</u>

A.	Single family residential	\$ 25.00
B.	Commercial (per single family equivalent)	\$ 25.00

Connection Charge:

A. 5/8" $500.00 + gross up
B. Meter larger than 5/8" - actual cost of meter and installation

Meter Testing Fee: $ 20.00

New Water Customer Charge: $ 27.00

Reconnection Charge:

A. If water service is cut off by the utility for good cause $ 27.00
B. If water is disconnected at the customer's request $ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base facility charge for the service period they were disconnected).

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of September 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-796, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Harrco Utility Corporation, 8601 Barefoot Industrial Road, Raleigh, North Carolina, for Authority to Increase Rates for Sewer Utility Service in Its Service Areas in Durham and Wake County, North Carolina	AMENDED RECOMMENDED ORDER GRANTING PARTIAL RATE INCREASE AND SUSPENDING CONNECTIONS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina at 7 p.m., on September 15, 1992, and on October 29, 1992.

BEFORE: Hearing Examiner Rudy Shaw

APPEARANCES:

For Harrco Utility Corporation:

Samuel Roberti, Attorney at Law, Roberti, Wittenberg, Holtkamp & Lauffer, 100 East Parrish Street, Suite 200, Durham, North Carolina 27701

For the Using and Consuming Public:

Victoria O. Hauser, Staff Attorney, Public Staff- North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27627-0520

SHAW, HEARING EXAMINER: On April 23, 1992, Harrco Utility Corporation (Harrco, the Applicant or Company) filed an application with the Commission seeking a rate increase for providing sewer utility service in all its service areas in North Carolina.

On May 12, 1992, the Commission issued an Order declaring a general rate case, suspending the proposed rates, requiring public notice, and scheduling a public hearing for September 15, 1992.

On August 19, 1992, the Public Staff filed a Motion to Dismiss the proceeding because of Harrco's failure to comply with certain bonding requirements. The Public Staff in that motion further requested in the alternative that the hearing be rescheduled for 30 days due to Harrco's failure to provide audit material in a timely fashion. On September 3, 1992, the Commission issued an Order scheduling the hearing of expert testimony on October 29, 1992, and designating the hearing on September 15, 1992, for customer testimony only.

On October 9, 1992, the Public Staff prefiled the testimonies of Kenneth Rudder, Utilities Engineer, and Bridget Szczech, Staff Accountant, and the affidavit of Gary Strickland, Financial Analyst with the Public Staff.

The hearings were held as scheduled. At the September 15 hearing, 14 customers testified. At the October 29 hearing, Lexie Harrison, president of Harrco, testified for the Applicant, and Kenneth Rudder and Bridget Szczech testified for the Public Staff.

On November 16, 1992, Harrco filed four late filed exhibits and its response to the Public Staff's motion to dismiss. The Public Staff filed a response on November 23, 1992.

On January 7, 1993, the Applicant filed a late-filed exhibit as requested by the Hearing Examiner.

Based on the evidence adduced at the hearings and the entire record in this docket, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. Harrco provides sewer utility service to six residential subdivisions (Park Ridge, River Oaks, Sheffield Manor, Stonebridge VI, Stone Creek, and Woods of Tiffany in Wake County and Hardscrabble Subdivision in Durham County) in North Carolina. These systems served a total of 151 residential and five non-residential customers at the end of the test year.

2. Customers testified to some service concerns, in addition to objecting to the amount of the increase.

WATER AND SEWER - RATES

3. Public Staff witness Rudder testified that the service provided by the Applicant is adequate.

4. The Applicant's existing and proposed sewer rates are as follows:

Monthly Service Charges:	Existing	Proposed
Residential flat rate	$ 21.00	$ 45.00
Non-residential flat rate	$ 72.00	$ 135.00
Connection Charges:		
Sheffield Subdivision	None	-
Stone Creek Subdivision	None	-
Stonebridge VI Subdivision	None	-
Park Ridge Subdivision	None	-
River Oaks Subdivision	None	-
Tiffany Subdivision	$3,000.00	-
Hardscrabble Subdivision	$3,150.00	-
All service areas	-	$3,250.00

5. The Public Staff recommended that the requested increase in connection fees be denied.

6. The Applicant has a service contract with its owner, Harrco Construction Company, which has not been submitted to the Commission for approval.

7. The test period for use in this proceeding is the twelve-months ended December 31, 1991.

8. The Applicant's original cost rate base at the end of the test period is $19,404.

9. The reasonable level of operating revenues for the test period under present rates is $ 35,386.

10. The reasonable level of operating revenue deductions requiring a return under present rates is $72,274, comprised of the following items:

Contract services	$ 2,474
Salaries and wages	12,116
Benefits	757
Electric power of pumping	2,880
Purchased water	1,069
Administrative and office	3,229
Maintenance and repairs	19,783
Testing fees	13,774
State permit fee	0
Tank pumping charges	8,580
Wake County inspection fee	3,999
Rate case	640
Depreciation	1,730
Payroll taxes	1,243
Total	$72,274

11. The Applicant was ordered to file bonds totaling $50,000 for its five systems or to initiate transfer proceedings by June 29, 1992, in the Commission Order Denying Bonding Proposals and Requiring Acceptable Bonds or Securities or Initiation of Transfer Proceedings in Dockets No. W-796, Sub 2, Sub 3, Sub 4, Sub 5, and Sub 6, dated February 28, 1992.

12. The Public Staff filed a Motion to Dismiss on August 19, 1992, in which it stated that no rate increase should be allowed. At the hearing the Public Staff requested that, in the event an increase should be allowed by the Hearing Examiner, the rates should reflect operating expenses only. In that instance, the Public Staff recommended the following rates, based on a temporary revenue requirement of $76,956:

Residential flat rate	$ 38.64
Non-residential flat rate	$115.92

13. The operating ratio method, which gives a margin on operating revenues deductions requiring a return, is the appropriate method of determining the revenue requirement for the Applicant in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1, 4, AND 7

These findings are based on the verified application, testimonies in this docket, and the official record of this Commission and involve matters that were uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2 AND 3

The evidence for this finding of fact is found in the testimony of the public witnesses and the testimony of Company Witness Harrison. Twenty-seven customers attended the hearing and 14 testified. All who testified objected to the proposed increase. Other complaints fell into four areas - 1) Lack of response on emergency after-hours calls, 2) Not being billed by the Company for extended periods after initial connection to the system, 3) Objection to the high grass on the central drain fields, and 4) Lack of communication and need for better public relations on the part of the Company.

The Company responded to each of these concerns. It acknowledged some problem with response to emergency after-calls that has been corrected. It indicated difficulty with having realtors and developers notify the Company when new accounts were begun, but did not feel that it was within the Company's power to avoid delayed bills at first due to this lack of timely notification. The Company noted that, given the nature of the drain fields, it could not mow during wet periods nor could it mow beyond a certain height necessary to the drain fields. It also noted that it felt part of the problem was lack of knowledge of the system by the customers and indicated that it intended to develop a brochure that would explain these matters to the customers. Harrco attached a copy of its proposed brochure to its proposed order filed on December 15, 1992. The Hearing Examiner has reviewed this brochure and finds its acceptable. However, the Hearing Examiner request the Public Staff to review said brochure and provide any suggested changes to Harrco (with copy to the Hearing Examiner) as soon as possible.

Public Staff witness Rudder testified to having conducted a field inspection in which he found the system to be well-maintained and the service adequate.

Consequently, it is the conclusion of this Hearing Examiner that Harrco should deliver the proposed brochure, with any changes recommended by the Public Staff, to all its customers. The Hearing Examiner also is of the opinion that the service provided by the Company is adequate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony of Public Staff Witness Rudder. The Applicant has contracts with developers that specifically state the amount of the tap on fee. The Applicant will have to arrange with the developers to modify the contracts before applying for the increase. The Applicant is reminded that the increase must be approved by the Commission and that no contracts should be finalized until such approval is granted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is in the testimony of Public Staff Witness Rudder. Harrco Construction Company (HCC) currently provides various maintenance services for the Applicant in connection with the maintenance of LPP waste disposal systems. All items are under a verbal understanding between the two companies.

The verbal understanding constitutes a contract between the companies. The Applicant should reduce this contract to writing and submit this contract to the Commission for approval. Mr. Harrison is president of the Applicant and HCC, therefore, this contract is a contract between affiliated entities at less than an arms length. G.S. §62-153 provides in part as follows:

> (a) All public utilities shall file with the Commission copies of contracts with any affiliated or subsidiary holding, managing, operating, constructing, engineering, financing, or purchasing company or agency...
>
> (b) No public utility shall pay any fees, commissions, or compensation of any description whatsoever to any affiliated or subsidiary holding, managing, operating, constructing, engineering, financing, or purchasing company or agency for services rendered or to be rendered without first filing copies of all proposed agreements and contracts with the Commission and obtaining its approval....

While it is clear that the Applicant has violated G.S. §62-153 in the signing of the contract without first having obtained the Commission approval, the Hearing Examiner does not feel that penalties should be assessed given the fact this a first offense. The Applicant, however, must submit this contract for approval and should be warned that all future contracts must be submitted for Commission approval as required by statute.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding is contained in the testimony of Ms. Szczech, who testified that she included in sewer plant in service only those items for which the Company provided supporting documentation. Ms. Szczech further testified that she calculated amounts for accumulated depreciation and depreciation expense after considering her adjustments to sewer plant in service. Finally, Ms. Szczech stated that she made an adjustment to include an amount for cash working capital, net of average tax accruals.

The Hearing Examiner concludes that the Public Staff's adjustments, which were uncontested, are appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding is contained in the testimony of Mr. Rudder and was not controverted by the Company. It is the conclusion of the Hearing Examiner that this amount is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding is contained in the testimony of Mr. Rudder and Ms. Szczech.

The Applicant disagreed with the Public Staff's recommendations with respect to the following items: contract services, salaries and wages, benefits, administrative and office, testing fees, tank pump charges, state permit fee, rate case expense, and payroll taxes.

Contract Services

This amount was amended from Public Staff testimony of Ken Rudder by further supporting documentation filed by the Company subsequent to the hearing.

Salaries and Wages

The application does not include an amount for salaries and wages. During the Public Staff's investigation, the Company requested that $20,000 be pro-rated into the rate case for Mr. Harrison's annual salary. The Public Staff reviewed the supporting documentation for the $20,000 annual salary level and determined that the $20,000 figure was unreasonable. Therefore, the Public Staff recommended in prefiled testimony that $12,116 be included for Mr. Harrison's salary. The amount recommended was based on the salary level recommended by the Public Staff in Docket No. W-796, Sub 1. The Public Staff adjusted the level recommended in Sub 1 to reflect the growth in the number of systems operated by Harrco Utility Corporation.

The Company estimated that Mr. Harrison works approximately 1,000 hour per year on sewer utility operations. Therefore, the $20,000 annual salary level constitutes a pay rate of approximately $20 per hour. Several of the duties performed by Mr. Harrison do not command a rate of $20 per hour. Some examples include bookkeeping, coordinating dealing with the Commission, customer relations, general management of Harrco Utility Corporation, contract service negotiations, and coordination of LPP maintenance services. Mr. Harrison performs additional duties such as Operator in Responsible Charge for all subsurface waste treatment systems and 24 hour response to emergency calls which require certification as a wastewater operator. These duties command a higher rate than the other duties previously mentioned. However, it appears unreasonable that the average rate for all the duties performed is $20 per hour.

In addition, the Company stated that some of the hours worked were on weekends and holidays. During direct examination, Mr. Harrison agreed that about 500 of the hours he worked a year were not within normal business hours. In addition, when asked during cross-examination, "... the majority of work that is done on the system could be done during regular working hours?" , Mr. Harrison responded, "Hopefully, the majority of it is done". It appears from the evidence in this docket that with the exception of emergency situations, the duties performed by Mr. Harrison could be done within normal business hours.

Based on the evidence in this docket, the Hearing Examiner is of the opinion that the Public Staff's recommended salary level of $12,116 is reasonable and the appropriate amount to be included for salaries and wages in this proceeding.

Benefits

The application does not show any amount for benefits paid in connection with contract services. During the hearing, the Public Staff agreed to include an amount for benefits provided for contract secretarial services upon sufficient supporting documentation. The Applicant's accountant provided supporting documentation and the Public Staff is recommending that $757 be included for the cost of the medical insurance provided to the secretary. The Hearing Examiner is of the opinion that $757 is reasonably representative of benefits related to the contract secretarial services.

Administrative and Office

The Company included $6,503 on its application for administrative and office expense. The Company did not present itemized support for the figure included on its application. The Public Staff included in its prefiled testimony the level of administrative and office expense supported by documentation provided by the Company. The Public Staff included rent, postmaster/printing charges, CPA services, attorney fees, other professional fees, bank service charges, and check printing charges which totaled $1,955. Harrco Utility Corporation bills Harrco Utility Corporation $400 per month for rent and secretarial services. The Public Staff testified that it included an amount for secretarial services in its prefiled testimony based on the $5.50 per hour rate provided by the Company. The Public Staff determined that 39 hours per month for secretarial services was appropriate for this Company. A residual amount of $510 per year with $446 allocated to sewer operations was included in administrative and office expense for rent. During the hearing, it was determined that the secretary's rate was actually $6.05 per hour. Therefore, the rent amount to be included in this proceeding is $1,969 per year with $1,720 allocated to sewer operations. The other amounts included in administrative and office expense were uncontroverted and have not changed.

Based on the evidence in this docket, the Hearing Examiner is of the opinion that the Public Staff's recommended level of $3,229 for administrative and office expense is reasonable and the appropriate amount to be included in this proceeding.

Testing Fees

This amount was amended from Public Staff testimony of Ken Rudder by further supporting documentation filed by the Company subsequent to the hearing.

Tank Pumping Charges

This amount was amended from Public Staff testimony of Ken Rudder by further supporting documentation filed by the Company subsequent to the hearing. Mr. Rudder initially recommended $145 per house for the pumping expense. However, based on information presented at the hearing, Mr. Rudder increased this amount to $165 per house.

The Applicant had requested $165 per house for pumping and $35 per house for location and uncovering the tank. However, in the opinion of the Hearing Examiner, the Applicant did not present sufficient evidence to justify the additional $35 expense. Based on these findings, the Hearing Examiner agrees with the tank pumping charges recommended by the Public Staff.

State Permit Fee

The Applicant pays a non-discharge permit fee for each of its sewer systems included an amount of $3,273 for their expense. Mr. Rudder indicated that 3,340 was the proper amount for the expense. However, Mr. Rudder further testified that the responsibility for administration of the nondischarge permits have been transfered from the Division of Envinromental Management (DEM) to the Division of Environmental Health (DEH) and that DEH will not be assessing this fee until such time as the North Carolina Legislature authorizes these fees. Mr. Rudder testified that, if DEH were authorized to charge these fees, Harrco would be allowed to recover them as a pass-thru. The Hearing Examiner is of the opinion that the Public Staff recommendation of $0 is the proper amount for State Permit Fees in this proceeding. However, the Company should apply for a pass-thru of these expenses if authorized by the North Carolina Legislature.

Rate Case Expense

The application did not include an amount for rate case expenses associated with this proceeding. The Public Staff included a level of $570 in its prefiled testimony based on information proved by the Applicant. The Public Staff recommended in its prefiled testimony that additional supporting documentation for accounting and legal fees be provided before the rate case expense level is ultimately determined. The Applicant provied additional information on December 14, 1992. Based on that additional information the Public Staff recommends a level of $1,920 for rate case expenses amortized over three years for a level of $640 to be included in this proceeding.

Based on the evidence in this docket, the Hearing Examiner is of the opinion that the Public Staff's recommended level of $640 for rate case expenses is appropriate.

Payroll Taxes

The application did not include an amount for payroll taxes associated with the contract secretarial services. At the hearing, the Public Staff agreed to include the payroll taxes associated with the contract secretarial services upon sufficient supporting documentation. The Applicant's accountant provided the amount of payroll taxes associated with the contract secretarial services. Therefore, the Public Staff recommends that $209 be included in payroll taxes for the contract secretarial services. The Hearing Examiner is of the opinion that $1,243 is the appropriate amount of payroll taxes to be reflected in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 AND 12

The evidence for this finding is contained in the affidavit of Mr. Strickland and the testimony of Ms. Szczech and Mr. Rudder. The Public Staff proposes that the Applicant be denied a rate increase until the Applicant fulfills the Commission's Orders in Docket No. W-796, Subs 2,3,4,5, and 6 concerning the bonding requirement. In the alternative, the Public Staff recommends that the Applicant be granted a temporary revenue requirement which would allow the Applicant to cover it expenses without the opportunity to earn a return on its operating revenue deductions until the Applicant fulfills the Commission's Orders concerning bonds. During the hearing, Mr. Harrison agreed that as of October 29, 1992, Harrco Utility Corporation was not in a position to post the bonds nor to transfer the systems. The Hearing Examiner is aware that the Applicant is indeed not in full compliance with the Commission's Orders in Docket No. W-796, Subs 2,3,4,5 and 6 concerning bonds. The Hearing Examiner is further of the opinion that Harrco appears to have deligently tried to transfer its system.

Based on the above, the Hearing Examiner is of the opinion that Harrco should be allowed to increase its rates to the level of expenses found just and reasonable by the Public Staff; however, the Hearing Examiner rejects the Public Staff's position that Harrco should be allowed to recover only its expenses without earning a return.

The Hearing Examiner finds that the rates should be as follows:

Residential flat rate	-	$ 43.25
Non-Residential flat rate	-	$129.75

Based on Harrco being in noncompliance with the bonding requirements, the Hearing Examiner finds that until Harrco is in full compliance with the bonding requirements, the Company should not be allowed to add additional lots to its sewer systems for which building permits were not issued on or before January 12, 1993. The Company has estimated its customer base at the end of January 1993 on its late-filed exhibit dated January 5, 1993.

Furthermore, any collections of monies in excess of the expenses found to be reasonable in this docket should go into an interest bearing escrow account to be set up by the Company. The purpose of this escrow account will be to collect monies to be applied to the posting of the required bonds. Once this account has accumulated $10,000, the Applicant shall notify the Commission and shall use those monies to secure one of its required bonds.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding is contained in the prefiled testimony of Public Staff witness Szczech. Although the Public Staff did not recommend a rate increase because of the bonding issue, Ms. Szczech's prefiled testimony shows that, had the Company posted the bonds as required, the Public Staff's recommendations would be that the Company be allowed the opportunity to earn a return of 9.5% on its operating revenue deduction. The 9.5% number and the operating ratio method were not controverted by the Applicant.

Therefore, based on the Hearing Examiner findings elsewhere in this Order, the Hearing Examiner finds that a 9.5% return on operating revenue deductions is appropriate in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the Schedule of Rates, attached hereto as Appendix A, is approved for sewer utility service provided by Harrco Utility Corporation in all the service areas in North Carolina.

2. That the Schedule of Rates is hereby considered filed with the Commission pursuant to G.S. 62-138.

3. That the Schedule of Rates shall become effective for service rendered on and after the effective date of this Order.

4. That all collections of monies in excess of the expenses found to be reasonable in this docket shall go into an interest bearing escrow account to be set up by Harrco. That once <u>all</u> the bonds required by Commission Order of February 28, 1992, have been posted, the Applicant may close out this escrow account.

5. That the Applicant is prohibited from adding additional lots (customers) to any of its service areas on which a building permit was not issued prior to January 13, 1993. Prior to adding any additional lots to any of its service area Harrco shall file a copy of the building permit with the Commission with a copy to the Public Staff. Once all the bonds required by Commission Order of February 28, 1992, have been posted, this requirement will be lifted.

6. That Harrco shall file bimonthly reports on its progress in complying with Commission Order Denying Bonding Proposals and Requiring Acceptable Bonds and Securities or Initiation of Transfer Proceedings. Said reports should also show the amount of monies in the escrow account required in Ordering Paragraph No. 4 above and list, by subdivision, the number of actual sewer connections. The first report shall be filed on or before February 26, 1992, and bimonthly thereafter. Once Harrco has posted all the bonds required by Commission Order of February 28, 1992, this reporting requirement will be lifted.

7. That a copy of the Notice to Customers, attached hereto as Appendix B, and a copy of the Schedule of Rates shall be mailed with sufficient postage or hand delivered to all Harrco's customers in conjunction with the next regularly scheduled billing process.

8. That the Public Staff is requested to review and comment on the Applicant proposed brochure attached to the proposed order filed on December 15, 1992. The Applicant shall incorporate into said brochure any changes and/or additions requested by the Public Staff and deliver a copy of the brochure to its customers.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

SCHEDULE OF RATES
for
HARRCO UTILITY CORPORATION
for providing sewer utility service in
PARK RIDGE, RIVER OAKS, SHEFFIELD MANOR, STONEBRIDGE VI,
STONE CREEK, AND WOOD OF TIFFANY SUBDIVISIONS
Wake County, North Carolina
and
HARDSCRABBLE SUBDIVISION
Durham County, North Carolina

Flat Sewer Rates:

Residential	$ 43.25
Nonresidential	$129.75

Connection Fee:

* Park Ridge, River Oaks, Sheffield Manor, Stonebridge VI, and Stone Creek Subdivision	-0-
Woods of Tiffany	$3,000.00
Hardscrabble	$3,150.00

Reconnection Charges:
If sewer service discontinued at customer's request: $ 15.00

Bills Due: On billing date

Bills Past Due: 25 days after billing date

Billing Frequency: Shall be monthly for service in arrears

Finance Charge for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

*Unless provided differently by contract approved by and on file with this Commission.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-796, Sub 7, on this the 3rd day of February 1993.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

DOCKET NO. W-796, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Harrco Utility Corporation, 8601 Barefoot Industrial Road, Raleigh, North Carolina, for Authority to Increase Rates for Sewer Utility Service in Its Service Areas in Durham and Wake County, North Carolina	)	NOTICE TO CUSTOMERS

BY THE HEARING EXAMINER: Notice is hereby given that the North Carolina Utilities Commission has granted a rate increase to Harrco Utility Corporation for all of its sewer operations in North Carolina.

The new rates were approved after application in April 1992, the audit and investigation by the Public Staff, and public hearings on September 15 and October 29, 1992.

The rates are shown on the attached Schedule of Rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. W-796, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Harrco Utility Corporation, 8601 Barefoot Industrial Road, Raleigh, North Carolina, for Authority to Increase Rates for Sewer Utility Service in Its Service Areas in Durham and Wake County, North Carolina	)	ORDER ON COMMENTS AND REQUEST FOR CLARIFICATION

BY THE HEARING EXAMINER: On January 12, 1993, the Hearing Examiner issued his Recommeded Order Granting Partial Rate Increase and Suspending Connection in the above-captioned matter. On January 26, 1993, Harrco Utility Corporation (Harrco) filed comments and requested changes to the Recommended Order. On January 27, 1993, the Public Staff filed a request for clarification of certain portions of the Recommended Order and its comments to Harrco's January 26, 1993, filing.

The Hearing Examiner has carefully reviewed the requests by the Public Staff and Harrco and reissues his Amended Recommended Order incorporating the changes and clarifications which are, in his opinion, appropriate.

IT IS, THEREFORE, ORDERED that the attached Order entitled Amended Recommended Order Granting Partial Rate Increase and Suspending Connections replaces and supercedes the Recommended Order issued on January 12, 1993, in this matter.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of February 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-6, SUB 16

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Regional Investments of Moore, Inc., d/b/a Pinehurst Water and Sanitary Company, Inc., Post Office Box 5500, Pinehurst, North Carolina 28374, for Authority to Transfer the Water and Sewer Utility Systems Serving in and Around the Village of Pinehurst, North Carolina to the Moore Water and Sewer Authority (Owner Exempt from Regulation)	ORDER APPROVING APPLICATION UPON CONDITION THAT THE LOCAL GOVERNMENT COMMISSION APPROVES MOWASA'S FINANCING OF THE PURCHASE

HEARD: July 20, 1993, September 21, 1993, Village Hall Meeting Room, 10 Village Way, Pinehurst, North Carolina

August 19, 1993, Agricultural Extension Auditorium, 706 Pinehurst Ave., Carthage, North Carolina

BEFORE: Commissioner Charles H. Hughes, Presiding and Chairman John E. Thomas; and Commissioner Laurence A. Cobb

APPEARANCES:

For the Applicant:

Edward S. Finley, Jr., Hunton & Williams, Attorneys at Law, Post Office Box 109, Raleigh, North Carolina 27602

For the Village of Pinehurst:

Warwick Fay Neville, Post Office Box 4420, Pinehurst, North Carolina 28374

For the Using and Consuming Public:

A. W. Turner, Jr., Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29510, Raleigh, North Carolina 27626

Lorinzo L. Joyner, Margaret A. Force, Assistant Attorneys General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: This proceeding was commenced on May 12, 1993, with the filing of an application by Regional Investments of Moore, Inc. ("RIM", "Company", or "Applicant") for Abandonment of Public Utility Franchise of the water and sewer systems serving an area in and around the Village of Pinehurst.

On June 3, 1993, the Commission issued an Order scheduling the matter for hearing.

On July 15, 1993, the Village of Pinehurst ("Village") filed a Petition to Intervene.

On July 15, 1993, the North Carolina Attorney General gave Notice of Intervention pursuant to G. S. 62-20.

By Order of July 16, 1993, the Commission allowed the intervention of the Village and Minnie Burgman.

On July 16, 1993, the Public Staff filed a motion to bifurcate the hearing so that certain tax and accounting issues arising from Orders in Docket No. M-100, Sub 113, could be addressed in a hearing subsequent to July 20, 1993.

By Order issued July 23, 1993, the Commission granted the Public Staff's Motion and scheduled a hearing on the tax and accounting issues for August 19, 1993.

This proceeding came on for hearing as scheduled in Pinehurst on July 20, 1993, at which time the Commission heard evidence from the parties and members of the public. The public witnesses were David Gorman, Dick Westcott, and William C. Kerchof. The Applicant presented the testimony of John Karscig, President of RIM. The Village presented the testimony of its Mayor, Albert L. Bethel.

On July 23, 1993, the Village filed a motion requesting that the Commission issue an order to summon MOWASA ("Moore Water and Sewer Authority") to appear before the reconvened hearing in Pinehurst on August 19, 1993, to testify on all matters relating to MOWASA's suitability and qualifications to own and operate the Pinehurst water and sewer facilities and upon its plans and intentions concerning the rates MOWASA will charge. The Village also sought to introduce additional evidence on these topics.

On August 5, 1993, RIM filed its response to the Village's motion, asking that the motion be denied.

On August 5, 1993, RIM filed a motion for approval of a refund plan and for cancellation of hearing. RIM stated that the Company and the Public Staff, after a series of negotiations, had resolved their differences over the tax refund issues. RIM represented that the Company and the Public Staff had agreed to the amount of the refund and the procedure for making the refund.

On August 5, 1993, the Public Staff filed a response to RIM's refund plan filing, expressing its satisfaction with the refund plan and stating that it did not believe that any accounting or tax matters remained to be heard.

On August 12, 1993, the Commission issued an Order denying the July 26, 1993, motion of the Village. The Commission reaffirmed that the hearing would be held in Carthage on August 19, 1993, at which time the Public Staff would make a presentation on the tax and accounting issues.

The hearing was conducted in Carthage on August 19, 1993, as scheduled. At the hearing, the Village suggested that notice of the August 19, 1993, hearing may not have been provided.

On August 24, 1993, RIM filed an amendment to the August 5, 1993, refund plan. In the amendment, the amount of refund per customer was restated.

On September 1, 1993, the Commission issued an Order rescheduling the hearing on the tax and accounting issues for September 21, 1993, in Pinehurst. The September 21, 1993, hearing was conducted as scheduled. John Karscig and Dick Westcott testified. The Public Staff represented that it was satisfied with RIM's August 24, 1993, amendment to the refund plan.

Upon careful consideration of all the evidence presented at the hearings and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. The present holder of the franchise for the water and sewer systems serving the area in and around the Village of Pinehurst is Regional Investments of Moore, Inc. d/b/a Pinehurst Water and Sanitary Company, which is a public utility company duly organized under the laws of North Carolina and subject to the jurisdiction of this Commission. The Commission has jurisdiction over the utility franchises and assets and over RIM's request to transfer the franchise to an owner exempt from regulation.

2. Moore Water and Sewer Authority is a water and sewer authority and a public instrumentality exercising essential governmental functions pursuant to G.S. 162A-6.

3. After the transfer, the systems will be operated by MOWASA under the authority of the Water and Sewer Authority Act, G.S. 162A-1 et seq. Pursuant to G.S. 62-3(23)(a), the water and sewer system operated by MOWASA will not constitute a public utility within the meaning of Chapter 62 of the General Statutes.

4. After the transfer the systems will be operated by those personnel currently operating it for Applicant.

5. The transfer of the assets will not adversely affect the adequacy of service now received from the systems.

6. MOWASA intends to continue to charge the water and sewer rates approved by the Commission for RIM in Docket No. W-6, Sub 10, in an Order dated October 17, 1988.

7. MOWASA, however, intends to increase tap and impact fees for new connections from $361 for water, $281 for sewer, and $361 for irrigation to $1,300 for water, $1,300 for sewer, and $1,300 for irrigation.

8. While holding the certificates of convenience and necessity issued by this Commission, RIM has fulfilled its public utility obligations and responsibilities.

9. As a publicly owned entity, MOWASA pays no income or North Carolina property taxes. MOWASA may borrow money and pay interest that is not taxable as income to the lender.

10. MOWASA potentially can provide service at lower costs as a result of its status as a governmental water and sewer authority.

11. The individuals in charge of operating MOWASA have experience in managing, operating, and running a water and sewer system.

12. MOWASA presently manages the waste water treatment plant at Addor that treats the sewage from Pinehurst, Southern Pines, Aberdeen, and Pinebluff.

13. One of the goals of MOWASA is to coordinate the water and sewer operations on a county-wide or regional basis.

14. Due to a scarcity of ground water sources in Moore County, centralization and regionalization may enhance the ability of the County to insure for its citizens a reliable and economical source of water supply.

15. The contract entered into between RIM and MOWASA was reached after one and one half years of arms length negotiations.

16. Centralization of operations under MOWASA provides the potential for economies of scale and savings in areas such as testing costs required by the Federal government.

17. The transfer of the water and sewer systems from RIM to MOWASA is also subject to the jurisdiction of the North Carolina Local Government Commission, which has the statutory authority to approve or disapprove the financing associated with the purchase of these systems. The approval of the transfer by the Commission herein shall be subject to the condition that the Local Government Commission approves the acquisition and financing of the water and sewer systems by MOWASA.

18. The potential for environmental cleanup and remediation should MOWASA seek to reclaim use of oxidation lagoons MOWASA will purchase from RIM is insufficient ground for disapproval of RIM's request.

19. The existence of restrictions on water use during hot summer months in some years forms no basis for disapproving RIM's request to relinquish its franchises and public utility obligations.

20. The longstanding dispute between the Village and the owners of the water system over the responsibility for adding and maintaining fire hydrants is insufficient justification for disapproving this application. RIM should be required, however, to repair all existing fire hydrants located on the Company's water system prior to transfer of the system to MOWASA.

21. The sewer connections in the Pinemere service area are properly connected to RIM's sewer collection system.

22. RIM should refund $499,262 plus interest on any unrefunded amount after the first bill credit at the statutory rate of 10%, representing revenues collected by RIM refundable based on orders in Docket No. M-100, Sub 113.

23. Refunds should be made in accordance with the refund plan submitted by RIM on August 5, 1993, as amended on August 24, 1993.

24. Refunds should be made as bill credits in accordance with the refund plan.

25. Money for the refunds should be placed into an escrow account from which MOWASA will make refunds as bill credits.

26. RIM shall remain subject to the Commission's jurisdiction for the sole purpose of bearing responsibility for making refunds and only for so long as the full refund has not been made.

27. Any refunds due will be offset by any outstanding balance owed by utility customers.

28. RIM, in conjunction with MOWASA, shall file monthly reports detailing any refund activity.

29. Subject to the approval of the Local Government Commission on MOWASA's financing of the purchase, the proposed transfer of the public utility franchises is in the public interest and consistent with the public convenience and necessity.

CONCLUSIONS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 16

The evidence supporting these findings of fact is contained in the testimony of RIM witness Karscig and in the Company's application. This evidence is essentially uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 17

Village witness Bethel and certain of the public witnesses addressed the issue of the purchase price to be paid by MOWASA for the water and sewer systems. Witness Bethel alleges that the purchase price is too high. RIM witness Karscig testified that the terms of the agreement were negotiated over a one and one-half year period through an extensive arms-length process. The Commission notes that the Village has raised this same issue before the Local Government Commission, an agency that must authorize MOWASA's financing of its acquisition, and that Mayor Bethel conceded that this is an issue more appropriately resolved by that Commission.

Ordinarily, in the transfer of public utility water and sewer systems from the seller to the purchaser, the Commission also examines whether or not the purchaser is financially able to purchase and operate the systems in a manner that will not adversely affect service to the customers. In this proceeding, however, the approval of the financing by MOWASA is also subject to the jurisdiction of the Local Government Commission. See Agreement for Sale of Assets, especially Article I, Sections 1.2(A)(2), and 1.4. The parties to this proceeding recognize the critical role of the Local Government Commission in examining MOWASA's acquisition of the water and sewer assets from the standpoint of financial feasibility. The Commission notes especially, as did the Applicant in its Proposed Order, that Mayor Bethel testified that the question of financing is a matter more appropriately for the Local Government Commission to consider and decide. Admittedly the evidence before the Commission is sketchy on the details of MOWASA's financing of the purchase price. The Local Government Commission has the expertise to examine MOWASA's financing of the purchase price and has the statutory mandate from the legislature to approve or disapprove such financing. The Commission is of the opinion, and so concludes, that it should defer to the Local Government Commission on this aspect of the transfer. Consequently, the Commission approves the transfer herein subject to the condition that the Local Government Commission approves the financing proposed by MOWASA for the purchase of the RIM water and sewer systems.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The Village argues that the Commission should withhold approval of this requested transfer until certain potential costs and liabilities can be identified. The potential liability identified by the Village is the possible groundwater contamination from property formerly operated as oxidation lagoons. MOWASA intends to purchase this property from RIM. The Village presented portions of certain engineering reports from MOWASA's due diligence investigation referring to the possibility of contamination. Evidence for potential contamination consisted of samples from test wells that had been bored in proximity to the lagoons.

While engineering reports in February 1993 suggested the possibility of contamination from the lagoons, later reports dismissed the conclusions of the earlier reports and suggested that costs of remediation if MOWASA later seeks to reclaim the property should not be of concern.

MOWASA is satisfied that any risks it assumes are reasonable ones. The Village failed to show that such risks are unreasonable. The Commission determines that the evidence presented by the Village does not justify the relief the Village requests. The Village's evidence is equivocal at best and falls far short of evidence that shows that there is a legitimate environmental concern.

Moreover, the Village was unable to answer the question of how deferral of decision or disapproval of the transfer would protect Pinehurst residents from the potential of bearing the costs of environmental remediation. If RIM retains the systems, and if expensive remediation is required, it is logical to assume that RIM will seek to recover the costs from its ratepayers as will MOWASA. Moreover, MOWASA has a customer base larger than the Pinehurst customer base. MOWASA can spread any such costs over a wider base, and Pinehurst residents should thereby benefit from a transfer from RIM to MOWASA.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 19

Village witness Bethel argues that restrictions on water use during the hot summer months show that the system is insufficient to meet customer demand. He alleges that the assessment of RIM and MOWASA is that there should be a curb in peak demand. Mayor Bethel criticizes this response and indicates that the response by MOWASA is only understandable because MOWASA has a flimsy financial model. He claims that capital investment is needed or that a customer education program is necessary.

On cross-examination, Mayor Bethel agreed that usage of water for irrigation purposes was causing the need for requests for voluntary curtailment in usage. When asked about improvements that should be made, in the Village's opinion, Mayor Bethel mentioned the looping of mains and a ring main around the town to help alleviate pressure problems. He again stressed the need for customer education.

The Commission finds that the concerns expressed by Mayor Bethel on this issue are insufficient to reject RIM's request. Many systems encounter difficulty meeting peak summer demand in times of drought and excessive usage. It appears that the need to curtail usage in Pinehurst arises from excessive demand for nonessential purposes. There has been no showing that the benefits to be gained by having enough water to allow unlimited irrigation use outweigh the cost of adding new wells or storage capacity for example.

Mr. Karscig suggests that irrigation rates should be increased to see that those imposing the peak demand on the system for nonessential purposes bear a fairer share of the costs and thereby receive an appropriate price signal so as to control the peak in that fashion.

The record contains insufficient evidence that RIM has failed to take proper steps to alleviate this problem. There is no persuasive evidence that MOWASA will refuse to address the problem in the future.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

Pinehurst Mayor Bethel testified that RIM has failed, after repeated requests from the Village dating as far back as September 1988, to install fire hydrants in areas where residential growth necessitates the placement of additional hydrants. Mayor Bethel further testified that RIM has also ignored Village requests to perform necessary repairs to hydrants where caps are missing or other deficiencies exist and that repeated written requests for action on needed repairs go unanswered and unaddressed by RIM. Mayor Bethel stated that it was his understanding that RIM has the responsibility to provide and maintain fire hydrants.

RIM maintains that its tariffs only require the Company to provide water to the Village through the hydrants and that the $25 charge per year per fire hydrant is designed to reimburse RIM for the water used by the Village to fight fires, to test the hydrants, and for the other needs for which the Village uses water from the hydrants. In its proposed Order, RIM asserts that it did not make the investment in the existing hydrants, that the cost of hydrants is not in RIM's rate base, and that the topic of fire hydrants only comes up when the Company is engaged in a proceeding before the Commission and the Village wishes to thwart the Company in reaching its objectives.

The Commission takes judicial notice of the fact that the subject of fire protection has been an issue of considerable controversy for a number of years as reflected by various Orders entered by the Commission. For instance, in Docket Nos. W-6, Subs 10, 11, 13, and 14, the Village, through its fire chief, voiced complaints regarding inadequate fire protection and the Commission ordered the utility to consult with the Village in an attempt to solve the disputes regarding fire protection. In Docket Nos. W-6, Subs 10 and 11, witness Karscig testified that the water company was then conducting repairs on hydrants and making further improvements to increase fire protection capability. In a filing made on August 23, 1989, in Docket Nos. W-6, Subs 13 and 14, RIM submitted a report, as required by Commission Order dated February 23, 1989, which contains references to certain maintenance activities performed or agreed to by RIM with respect to the fire hydrants on its water system. Therefore, the Commission finds good cause to grant the portion of the Village's request to require RIM to complete any necessary repairs, including installing missing caps, on fire hydrants located on its water system prior to transfer of the system by RIM to MOWASA. The Commission does not, however, find good cause to require RIM to install any additional fire hydrants prior to the transfer. The Village can certainly request MOWASA to install additional fire hydrants once the system has been transferred.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 21

At the public hearing held on July 20, 1993, Mr. William C. Kerchof, a homeowner in the Pinemere service area, testified to his concern that he and several of his neighbors were not properly connected to RIM's sewer collection system. Mr. Kerchof alleged that the sewer laterals from several residences are connected to the sewer lateral of one home and only that home is directly connected to RIM's collection system. He further stated that MOWASA had informed him that they would not maintain such installations. Mr. Kerchof was concerned that if the transfer were approved, homeowner in his service area would "be placed in a terrible situation."

At the close of the hearing, the Commission ordered RIM to file an exhibit which addressed the sewer connection concerns expressed by Mr. Kerchof.

On July 26, 1993, John Karscig filed a letter addressing the concerns of Mr. Kerchof. In his letter, Mr. Karscig stated: "All customers in the vicinity of Mr. Kerchoff's (sic) residence are connected directly to our sewage collection system. No customers's (sic) service lateral is interconnected to those of other customers so that blockage on one sewer line disrupts service to another customer." Mr. Karscig further explained that, because the sewer mains near Mr. Kerchof's home are under the water level of Lake Pinehurst, the Company was required to extend a sewer line from a manhole on dry property into the right-of-way or easement along the shoreline. Each lot was then connected into this common extension.

Mr. Karscig further stated that he had had a conversation with Mr. Kerchof in 1981 concerning the sewer connection and had committed to him that his company was responsible for maintenance of the common facilities, including the sewer extension line onto which his sewer lateral is connected. Mr. Karscig explained that he has contacted Mr. Mitch Coleman, Executive Director of MOWASA, and that Mr. Coleman has indicated that MOWASA's responsibly would be the same as RIM's; i.e. MOWASA would be responsible for maintaining common lines up to the property line.

Based on the above, the Commission is of the opinion that RIM has adequately addressed the concerns expressed by Mr. Kerchof and that the sewer connections in Mr. Kerchof's service area have been properly installed and connected to RIM's sewer collection system.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 22 - 29

The evidence supporting these findings of fact is found in RIM's refund plan. This refund amount and refund plan were determined after substantial negotiation between RIM and the Public Staff. The refund plan provides for substantial refunds to customers. No party objects to the calculation of the refund amount or the mechanism for making the refund. After careful independent analysis, the Commission determines that the refund plan should be approved.

IT IS, THEREFORE ORDERED AS FOLLOWS:

1. That the transfer of the utility franchises of the water and sewer systems serving the area in and around the Village of Pinehurst, North Carolina, from Regional Investments of Moore, Inc., to Moore Water and Sewer Authority, an owner exempt from regulation, is approved, subject to the condition that the Local Government Commission approves the financing of the purchase by MOWASA. If the Local Government Commission does not approve MOWASA's financing of the purchase of the water and sewer systems, the Commission's conditional approval shall be withdrawn.

2. That RIM should refund $499,262 plus interest based on Orders in Docket No. M-100, Sub 113, in accordance with the refund plan submitted on August 5, 1993, as amended on August 24, 1993.

3. That prior to the transfer of the water and sewer systems to MOWASA, RIM shall repair all existing fire hydrants located in the Company's water system. Prior to said transfer, RIM shall file a written report setting forth its compliance with this Ordering Paragraph.

4. RIM shall remain subject to the Commission's jurisdiction for the purpose of (1) complying with Ordering Paragraph 3 above and (2) bearing responsibility for making the refunds ordered in Paragraph 2 above.

5. RIM, in conjunction with MOWASA, shall file monthly reports detailing any refund activity.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of October 1993.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-274, SUB 71
DOCKET NO. W-274, SUB 72

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina 27519, for Authority to Transfer the Water Utility System Serving Pinewood Subdivision in Wayne County, North Carolina, to the City of Goldsboro (Owner Exempt from Regulation) and In the Matter of Application by Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina 27519, for Authority to Discontinue Water Utility Service to Country Acres Subdivision in Wayne County, North Carolina	ORDER DETERMINING REGULATORY TREATMENT OF GAIN ON SALE AND LOSS ON ABANDONMENT OF FACILITIES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on February 23, 1993.

BEFORE: Commissioner Robert O. Wells, presiding, Chairman William W. Redman, Commissioners Sarah Lindsay Tate, Julius A. Wright, Charles H. Hughes, Laurence A. Cobb, and Allyson K. Duncan.

APPEARANCES:

For the Applicant:

Robert F. Page, Crisp, Davis, Page, Currin & Nichols, Suite 400, 4011 Westchase Boulevard, Raleigh, North Carolina 27607

For the Using and Consuming Public:

Victoria O. Hauser, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Dffice Box 29520, Raleigh, North Carolina 27626-0510

BY THE COMMISSION: On August 13, 1992, the Commission issued an Order in Docket No. W-274, Sub 71, approving the transfer of ownership of the water utility system owned by Heater Utilities, Inc. (hereinafter referred to as "the Company" or "Heater"), which served the Pinewood Subdivision in Wayne County, North Carolina, to the City of Goldsboro. In Docket No. W-274, Sub 72, an Order was issued canceling the water utility franchise granted to Heater for Country Acres Subdivision in Wayne County, North Carolina. These orders stipulated that the issues of who should benefit from the gain or absorb the loss from the sale or discontinuance of the water systems were to be consolidated and decided in a separate hearing. By Order of September 2, 1992, the Commission scheduled a hearing in these dockets for February 23, 1993.

The Company prefiled the initial and rebuttal testimony of William E. Grantmyre, President, and Jerry H. Tweed, Director of Environmental and Regulatory Affairs, on January 11, 1993, and February 17, 1993, respectively. The Public Staff prefiled the testimony of Katherine A. Fernald, Supervisor of the Accounting Water Section, on February 10, 1993.

A Motion for Leave to File Comments as Amicus Curiae by Carolina Water Service, Inc. of North Carolina was filed in the above-captioned dockets on February 17, 1993. The motion was unopposed by the parties of record.

The hearing was held at the time and place noted above. William E. Grantmyre and Jerry H. Tweed testified on behalf of the Company. Katherine A. Fernald testified on behalf of the Public Staff.

Based upon the foregoing, the evidence adduced at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Both Heater's stockholder and the ratepayers of Heater share in the risks associated with the utility property used and useful to provide water and sewer service to the ratepayers.

2. The risks cited by Heater in this proceeding are not materially different from the risks considered in the Commission's decision in CWS Docket No. W-354, Subs 82, 86, 87 and 88.

3. Sales to municipal systems and sanitary districts result in advantages to the customers of transferred systems through generally lower rates, fire protection, better water quality, better storage, better production facilities, and more economies of scale.

4. The benefits cited by Heater in this proceeding are not materially different from the benefits considered in the Commission's decision in CWS Docket No. W-354, Subs 82, 86, 87 and 88.

5. The public policy issues discussed in this proceeding are not materially different from the public policy issues considered in the Commission's decision in CWS Docket No. W-354, Subs 82, 86, 87 and 88.

6. Legal fees incurred by the Company related to this proceeding are an essential component of the transactions and should be included in the gain/loss calculations. The costs associated with Heater's administrative employees for their time in these proceedings are not costs of a nature that would be in addition to those already included in the Company's cost of service at a reasonable and representative level.

7. The Company and the Public Staff stipulated at the hearing that the income taxes related to the gain and the loss should be calculated based on the book basis of the property.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 5

Whether Heater's remaining ratepayers should receive a portion of the gain on the sale of the Pinewood system is the main issue that was addressed by the witnesses in this proceeding. The evidence supporting these findings of fact appears in the testimony of Public Staff witness Fernald and Heater witnesses Grantmyre and Tweed.

The issue of which party, a utility's stockholders or its remaining ratepayers, should receive the benefits of gains on the sale of utility systems was addressed by witnesses in Docket No. W-354, Subs 82, 86, 87 and 88, the CWS cases, including witnesses Grantmyre and Tweed who testified in that proceeding. Based on the extensive evidence offered by all of the parties presenting evidence in that docket, the Commission concluded:

"That 50% of the gains on the sales of Beatties Ford/Hyde Park East, Genoa, Raintree, and Riverbend systems should be assigned to CWS's remaining ratepayers in a manner to be determined in CWS's next general rate case and that 50% of said gain should be assigned to CWS's shareholder(s)."

and

"After weighing all of the evidence the Commission concludes that the appropriate ratemaking treatment is that CWS and its remaining customers should share equally in the benefit of any gains resulting from the sales of facilities used to provide utility service in the Beatties Ford/Hyde Park East, Genoa, Raintree, and Riverbend subdivisions. The Commission emphasizes that CWS's remaining ratepayers will receive an equal portion of the benefit of only the amount of sales proceeds left after CWS's stockholders have recovered their investment and all reasonable transaction costs associated with the transfers."

Witnesses Grantmyre and Tweed have recommended to the Commission that it reconsider its decision in the CWS cases, that the benefits of a gain on the sale of a utility system be split 50/50 between a utility's stockholder(s) and its remaining ratepayers. Public Staff witness Fernald recommended that the gain on the sale of the Pinewood system be split 50/50 between Heater's stockholder and remaining customers. The Commission has carefully considered the testimony and recommendations of each witness on this issue and concludes that the gain on the sale of the Pinewood system should be shared equally between Heater's stockholder and remaining ratepayers. When the Commission reached its decision in the CWS cases, the Commission carefully evaluated the testimony presented by all witnesses in that proceeding. Witnesses Grantmyre and Tweed have presented no additional evidence which causes the Commission to reach a different decision in this proceeding.

Witnesses Grantmyre and Tweed cited the formula method of calculating the sales price used by Heater and public policy considerations as the primary aspects that the Commission should consider in determining that Heater's stockholder should receive 100% of the benefit of the gain on the sale of the Pinewood system.

RISK ANALYSIS

The parties to the CWS proceedings, including Heater Utilities, Inc., who intervened in the case, identified numerous risks associated with the public utility property and who bore the risks. The parties to the proceedings provided testimony on other factors, such as benefits to the transferring customers and public policy concerns. In that proceeding, the Commission adopted the principle that whoever assumes the risks associated with utility property should receive the gain. After considering all the evidence presented concerning risks and other factors, such as benefits and public policy, the Commission concluded that the gains should be allocated equally between the stockholder and the remaining ratepayers.

Public Staff witness Fernald testified that Heater had not presented any additional risks that Heater's stockholder must bear that were not discussed in the CWS cases. Company witness Grantmyre testified that the risks assumed by Heater's ratepayers and the risks assumed by Heater's stockholder are essentially the same as those articulated in the CWS case. Therefore, the Commission concludes that none of the risks cited by Heater in this proceeding are materially different from the risks considered in the Commission's decision in the CWS cases.

Based on the analysis done by the Commission in the CWS case and the fact that none of the risks cited in this proceeding are materially different from the risks cited in the CWS cases, the Commission concludes that both Heater's stockholder and the ratepayers of Heater share in the risks associated with the utility property used and useful to provide water and sewer service to the ratepayers.

In the CWS cases, the Commission stated:

> "The principle adopted herein--that whoever assumes the risks associated with utility property should receive the gain--has been recognized by this Commission in previous dockets and by commissions and courts in other jurisdictions, both state and federal."

Also, in its Order in the North Carolina Natural Gas (NCNG) rate case, Docket No. G-21, Sub 293, issued on December 6, 1991, the Commission concluded:

> "Because NCNG is a regulated utility, its stockholders are insulated from extraordinary losses by the ability to seek amortization of such losses through rate increases. In other words, the risk of extraordinary capital losses is shifted from stockholders to ratepayers by virtue of the regulatory process. This is a different situation from the normal unregulated business where stockholders expect to receive extraordinary gains such as appreciation in value of land, and they have a concomitant expectation that they will bear the risk of extraordinary losses.
>
> The risks that investors of regulated utilities do bear are compensated for in the allowed rate of return set by the Commission; any additional return from extraordinary gains would amount to an improper windfall since the concomitant risk of extraordinary losses does not fall upon utility investors. Indeed, to allow the Company to

keep the gain on sale in addition to the allowed return on equity would violate the North Carolina's Supreme Court's holding that the history of G.S. 62-133(b)

> 'supports the inference that the Legislature intended the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States....'

State ex rel. Utilities Commission v. Duke Power Co., 285 N.C. 377, 388, 206 S.E.2d (1974)."

As concluded earlier, both Heater's stockholder and the ratepayers of Heater share in the risks associated with the utility property used and useful to provide water and sewer service to ratepayers. Distributing 100% of the gain to Heater's stockholder would amount to an improper windfall for the stockholder to the detriment of the remaining ratepayers since a portion of the concomitant risk of extraordinary losses falls on the remaining ratepayers. Therefore, it would be inappropriate for Heater's stockholder to receive all of the gain when the remaining ratepayers have shared in the risks associated with the property.[1]

PUBLIC POLICY

Company witness Tweed testified that the focus in determining the distribution of the gain should be primarily public policy rather than risk. Witness Tweed testified that the Commission's decision in the CWS cases is working to the detriment of the ratepayers and industry. Witness Tweed testified that the Commission's decision has resulted in fewer sales to cities, higher negotiated sales prices, and utility companies forming separate corporations for systems.

In the CWS cases, the Commission determined that factors other than who bears the risks should be given appropriate consideration in deciding who should receive the gain. Public Staff witness Fernald noted that the Commission's decision in the CWS case was based on all the evidence presented concerning risks and other factors, such as benefits and public policy concerns.

The Commission concludes that factors other than risks, such as benefits and public policy concerns, should continue to be given appropriate consideration in reaching a determination as to who should receive the gain.

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[1] Heater cited the recent Supreme Court decision of State of North Carolina ex rel. Utilities Comm. v. Public Staff (Case No. 385A91, January 8, 1993) as a new potential risk to shareholders due to the Company's interpretation of dicta concerning treatment of abandoned plant. However, Heater acknowledges that it will not assert that interpretation in its pending rate case, and the issue is tangential to this proceeding. Therefore, the Commission does not consider it timely to undertake analysis of that decision at this time.

First, the Commission recognized public policy considerations in reaching its decision in the CWS case to share the gain equally between CWS's stockholder and remaining ratepayers. In reaching its decision in that proceeding, the Commission stated:

> "Furthermore, the Commission believes that factors other than a determination as to who bears the risks should be and have been given appropriate consideration in reaching a determination in this matter. The parties appearing in these proceedings agree that the customers on the systems being transferred would receive many benefits after being acquired by the city or sanitary districts. The Commission, as a matter of policy, recognizes the inherent advantages often associated with municipal and sanitary district service and in fact has actively sought municipal and county acquisition of troubled water and sewer systems under our jurisdiction. See, for example, Carolina Water Service, Inc. of North Carolina - Rate Increase Proceeding, Docket No. W-354, Subs 69 and 81 (Commission directed the company to negotiate the purchase of water in bulk from, or sale of troubled water systems to, the Asheville-Buncombe Water Authority). See also Cowan Valley Water System - Jackson County, Docket No. W-829, Sub 8 (Commission actively sought county bulk water service to a regulated water system under emergency operatorship). In reaching its decision in this matter, the Commission has given weight to the premise that if the stockholders are deprived of all of the gains on a potential sale of a system to a municipality, or similar entity, such a policy would remove any incentive to sell the system, thereby often depriving the customers of such system many benefits associated with municipal acquisition."

The primary public policy concerns testified to by witnesses Grantmyre and Tweed were the fact that the customers being transferred would receive a higher quality of service and would not be required to pay any tap fees, assessments or other charges. The benefit to transferring customers of no tap or connection fee cited by witness Grantmyre was a benefit presented to the Commission in the CWS cases and was considered by the Commission with all other evidence in reaching its decision in the CWS cases. In the CWS cases, witness O'Brien of CWS testified that one of the benefits to the Beatties Ford customers was that they would not have to pay a tap-on or connection fee. In the CWS cases, witness O'Brien also testified that the transferring customers would receive the benefits of the lower rates, the City's economies of scale, additional capacity, excellent quality of service, better water quality, fire protection, greater water supply and water storage capabilities, and greater and more constant pressure.

Based on the evidence presented in the CWS cases and in this case concerning benefits, the Commission concludes that the benefits cited by Heater in this proceeding are not materially different from the benefits considered in the Commission's decision in the CWS cases.

The public policy concerns connected with the transfer of the Pinewood system are not materially different from those involved in connection with the proposed transfers of the systems involved in the CWS cases. Therefore, the Commission concludes that from the perspective of public policy, the gain on the sale of the Pinewood system should be shared equally between Heater's stockholder and its remaining ratepayers.

FORMULA METHOD OF CALCULATING SALES PRICE

One reason presented by Heater witnesses Grantmyre and Tweed for providing 100% of the benefits of the gain on the sale of the Pinewood system to Heater's stockholder is the formula method used by Heater to calculate the sales price to be paid by the City of Goldsboro. Witness Grantmyre testified that because the customers on the Pinewood system received the benefit of the discounted sales price based on the formula method, there should be no further division of the gain with the remaining ratepayers.

The testimony of witnesses Grantmyre and Tweed concerned the fact that the formula method resulted in a relatively low transfer price, along with the fact that the customers being transferred would not be required to pay any tap fees, assessments or other charges.

Negotiations between utilities and municipalities for the purchase of water or sewer systems involve arms-length transactions between two parties intent on maximizing beneficial terms. The Commission's decision on the gain distribution should not affect the final price the parties agree upon. Since Heater used a pre-determined formula method to determine the sales price, it is not known whether Heater could have obtained a higher sales price based on a different type of negotiation with the City of Goldsboro. The circumstances, however, would tend to support the presumption that Heater had reasons beneficial to the Company for its freely chosen method of negotiation.

The Commission is not persuaded that the formula method used by Heater to determine the sales price resulted in unusual benefits to Heater's transferred customers or remaining customers. Further, the Commission is not convinced that the use of the formula method results in any benefits to the remaining customers of Heater who have shared in the risks associated with the utility property. The Commission concludes that Heater's use of the formula to determine the sales price of the Pinewood system is not reason to give its stockholder a greater share than 50% of the benefit of the gain on the sale of the Pinewood system.

ADVERSE CONSEQUENCES OF COMMISSION'S DECISION IN DOCKET NO. W-354, SUBS 82, 86, 87 AND 88

Witness Tweed testified that the Commission's decision in the CWS cases has worked to the detriment of the ratepayers and industry and should be contrary to public policy. The Commission disagrees. Tweed testified that the Commission's decision in those cases has resulted in the following consequences:

(1) fewer sales to cities
(2) higher negotiated sales prices
(3) establishing separate corporations for specific systems in order that stockholders can receive the benefit of 100% of the gain on the future sale of a system
(4) the proposal by CWS to establish system-specific rates
(5) a higher sales price for the Beatties Ford system
(6) the Riverbend system was never sold

In the CWS cases, witness Tweed testified that if the Commission flowed back a portion of the gains to ratepayers, sales prices would increase, there would be fewer sales to cities, and companies would set up separate corporations. The

Commission concludes that none of the public policy issues discussed in this proceeding are materially different from the public policy issues considered in the Commission's decision in the CWS cases.

The adverse consequences contended by witness Tweed are contradicted by documents and statements contained in the Commission's files that have been filed by other parties.

For example, in Comments as amicus curiae, CWS stated as follows:

> CWS would like to dispel the notion that its support for system specific rates is the result of the regulatory treatment of gains on sale. Rather, it is based on the fact that system specific rates will offer each community served greater choice in the level of service provided at rates that fairly reflect the cost of providing that service. As CWS has stated in the past, system specific rates will allow CWS the flexibility to provide the level of treatment desired by each individual community without concern that the added cost of such treatment will drive up the costs in other communities.

Witness Tweed testified that history has shown that the Commission's decision has resulted in companies setting up separate corporations for systems. He cited Carolina Trace Corporation - Docket No. W-1000, Sub 1, Transylvania Utilities, Inc. - Docket No. W-1000, Sub 2 and Burnett Utilities - Docket No. W-1022, as examples. He also stated that the Commission's decision on gains generated CWS's support for system specific rates. Witness Fernald testified that there are many reasons, other than gain on sale, why a utility would want to set up a separate corporation. She also testified that in the cases cited by witness Tweed each of the companies stated the reasons why it decided to set up a separate corporation, and none of the companies mentioned the gain on sale issue as a reason. She further testified that CWS cited its reasons for updating its position on uniform rates in Docket No. W-100, Sub 13, and it did not mention the gain on sale issue as a reason.

The Commission is not persuaded that the separate corporations and CWS's support of system specific rates were the result of the Commission's decision in the CWS cases. All of the companies cited by Heater had good reasons, other than gain on sale, for setting up separate corporations. There is no evidence in the record of this case or the cases cited by Heater to support Heater's statement that its decisions were a result of the Commission's gain on sale order.

The Commission is not convinced by evidence presented that the Commission's decision has resulted in fewer sales to cities. Testimony was presented in this proceeding that CWS, in addition to selling the Beatties Ford system at a price of $100,000 greater than the originally negotiated price, sold the Genoa/Raintree systems at a price less than was originally negotiated. As CWS sold one system at a higher price than was originally negotiated, sold another system at a lower price than was originally negotiated, and has not yet sold the Riverbend system, the Commission is not persuaded that the policy it established in the CWS cases of equally sharing the benefits of the gains on the sales of utility systems has resulted in adverse consequences sufficient to justify changing the policy in question.

Based on the risks and other factors, such as the benefits to the transferring customers and public policy goals, the Commission concludes that the gain on sale should be equally allocated between Heater's stockholder and the remaining ratepayers of Heater.

As noted earlier, the Commission recognizes the benefits to customers upon the transfer of systems to municipal operators or sanitary districts. It is the Commission's intent to continue to encourage such transfers where feasible and, accordingly, the Commission will continue to monitor the policy adopted herein with regard to any adverse consequences that such policy may have upon the future transfer of systems to municipal operators.

LOSS ON ABANDONMENT

Both the Public Staff and Company witnesses stated that the loss on abandonment should be shared the same way as the gain. Witness Fernald testified that in the next Heater rate case, 100% of the abandonment loss should be amortized, with no return on the unamortized balance, over an amortization period that results in the present value of the costs being shared approximately 50% by the ratepayers and 50% by the stockholder. This methodology is consistent with the Commission's treatment of abandonment losses in electric cases. The Company did not present any testimony on how the loss should be shared equally between ratepayers and stockholders. The Commission concludes that in the next general rate case, the abandonment loss should be recognized in a reasonable manner which effectuates a sharing of the loss between the stockholder and remaining ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact appears in the testimony of Public Staff witness Fernald and Heater witnesses Grantmyre and Tweed. Witness Fernald testified that legal and administrative costs related to proceedings before this Commission should not be included in the calculation of the gain and the loss. Witness Fernald testified that the revenue requirement approved in Heater's general rate case includes an allowance for reasonable levels of legal and administrative costs as ordinary operating expenses.

Witness Grantmyre testified that this proceeding is an integral part of the sales transaction and the costs should be included in the calculations of the gain and the loss. Witness Grantmyre also testified that in the last CWS rate case, the Commission adopted the Public Staff's recommendation to allow 50% of the costs related to CWS's gain proceeding to reduce the gains on sale.

The costs at issue in this proceeding are administrative labor costs associated with preparing for and appearing in Commission hearings related to these proceedings as well as attorney's fees for these proceedings. With regard to the legal fees incurred by Heater for outside counsel related to this proceeding, the Commission concludes that such costs are an integral part of these transactions and should be split equally between the ratepayers and stockholder. Since both the stockholder and ratepayers will receive an equal benefit as a result of this proceeding, it is only fair that each party absorb an equal amount of these costs. With respect to the administrative labor costs, the Commission is not persuaded that such costs for the time of Heater's administrative employees spent preparing for and appearing in Commission hearings related to the transfer and negotiating and closing the sale of the facilities are costs of the nature that would be in addition to those already included in the Company's cost of service at a reasonable and representative level. Accordingly, the Commission concludes that such costs should not be included as a component is the gain/loss calculations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

At the hearing, the Company and the Public Staff stipulated that the income taxes related to the gain and the loss should be calculated based on the book basis of the property. The Commission concludes that this stipulation is appropriate and should be accepted.

ENDING CONCLUSIONS

The Commission reaffirms the policy established in the CWS cases and concludes that the benefit of the gain on the sale of the Pinewood system should be shared equally between Heater's stockholder and its remaining ratepayers. This policy is fair and equitable to all parties.

Both Heater's stockholder and its ratepayers have shared the risks associated with the property that has been sold; therefore, Heater's stockholder and its remaining ratepayers should share the benefits of the gain on the sale of the Pinewood system. The Commission has considered the public policy aspects of the sale of the Pinewood system, recognizing the fact that the customers of the Pinewood system will receive a higher quality of service after the sale to the City of Goldsboro.

The Commission has also considered the fact that even though the benefits of the sale will be shared equally between Heater's stockholder and its remaining ratepayers, Heater will have the entire amount of capital representing the cost of its property plus the total net-of-tax gain on the sale available to it. This capital can be used by Heater for any corporate purpose. The ratepayers' portion of the gain represents a permanent form of cost-free capital for Heater if the ratemaking treatment approved for CWS is later approved by the Commission for Heater.

Based on all of these factors, the Commission concludes that the gain on the sale of the Pinewood system should be shared equally between Heater's stockholder and its remaining ratepayers. This policy is fair to all parties -- Heater's stockholder, Heater's transferred customers and its remaining customers. The ratemaking treatment of the remaining ratepayers' portion of the gain will be determined by the Commission in Heater's pending or next general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That 50% of the gain on the sale of the public water utility system owned by Heater Utilities, Inc., which serves the Pinewood Subdivision in Wayne County, North Carolina, shall be assigned to Heater's remaining ratepayers in a manner to be determined in Heater's pending or next general rate case consistent with the provisions of this Order, and that 50% of said gain shall be assigned to Heater's shareholder.

2. That the loss on abandonment of the Country Acres Subdivision system shall be recognized in a reasonable manner to be determined in Heater's pending or next general rate case consistent with the provisions of this Order so as to effectuate a sharing of the loss between the stockholder and the remaining ratepayers.

3. That Heater shall record 50% of the net-of-tax gain in a deferred account until the Commission determines the manner in which the benefit of the gain should be returned to Heater's remaining ratepayers.

4. That Heater shall file reports with the Commission and Public Staff concerning the calculations of the gain/loss and the workpapers supporting the calculations. Any party disagreeing with the calculations of the gain/loss may contest the amount of gain/loss in Heater's pending or next general rate case.

5. That Heater shall file journal entries related to the gain/loss, including the removal of the plant and associated accounts from Heater's books and records, in a manner consistent with the provisions of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of May 1993.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Commissioner Tate concurs
Commissioner Hughes dissents
Commissioner Cobb concurs
Commissioner Duncan joins Commissioner Tate's concurring opinion.

COMMISSIONER TATE, CONCURRING: I concur with this Order because I believe that accounting adjustment is correct. However, the Commission has an overriding responsibility to set public policy that is in the public interest. There is evidence in this case that our decision in the C.W.S. cases, Docket No. W-354, Subs 82, 86, 87 and 88 has discouraged sales from private water companies to cities. There is also evidence that planned sales have not taken place or that the sales price has been increased due to our decision. It is also alleged that water companies are forming separate corporations to circumvent the requirement to split the gains. In my view, none of these results are in the public interest of North Carolina. If additional proof is offered that our decision has prevented sales, the Commission should reverse the C.W.S. Order and conclude that good public policy is more important than an accounting practice.

Sarah Lindsay Tate, Commissioner

COMMISSIONER CHARLES H. HUGHES, DISSENTING: I respectfully dissent from the decision of the Majority in the instant proceeding. I would have allowed the Company to retain or bear 100 percent of the gain or loss on the sale/abandonment of the subject systems so as to encourage the sale of such systems to municipalities or to county-wide systems operated by governmental agencies. Encouragement to sell systems arises or is enhanced when companies are allowed the opportunity to retain 100 percent of the gain realized on such sales. I believe that such encouragement reflects good public policy, since the quality and price of water and sewer services, generally speaking, tend to be much more favorable when provided by a governmental agency.

The Majority in this case has largely based its decision on facts and circumstances that were present in an unrelated proceeding, i.e., the CWS case, and not on the weight of the evidence presented in this proceeding. The methodology utilized by the Company in establishing the sales price in this instance, which is described and discussed in the Majority's Order, was and is eminently reasonable. Further, no party to the proceeding contested the fact that the sale of the Pinewood system was in the best interest of the Company's customers, both customers being transferred and those remaining on the Company's other systems.

By denying the Company the opportunity to retain 100 percent of a gain from the sale of a system(s), the Commission is continuing a policy that can only serve to discourage the future sale of water and sewer systems to municipalities and to county-wide systems operated by governmental agencies. Such undesirable results are clearly evidenced by the record in this proceeding. Discouragement of such sales is a policy or practice to be shunned and not embraced. For the foregoing reasons, I dissent from the Majority's instant decision.

Charles H. Hughes, Commissioner

COMMISSIONER COBB, CONCURRING: I agree with the decision not to change our rulings with respect to gain and loss from the sale of water systems at the present time. I agree with Commissioner Tate that our decisions appear to have discouraged sales from private water companies to public utilities to the detriment of the public interest. However, great confusion could result if the Commission as presently composed were to change the rule only to have it changed again after three new Commissioners are installed in a few months. I would hope that the "new" Commission would revisit this question in the near future. I am prepared to do so.

Laurence A. Cobb, Commissioner

DOCKET NO. W-354, SUB 122

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Carolina Water Service, Inc.	)	
of North Carolina, 2335 Sanders Road,	)	ORDER DECLINING
Northbrook, Illinois, for Assistance	)	REQUEST FOR
Re: Selection of Elevated Storage Tank	)	ADVISORY OPINION
for Cambridge Subdivision	)	

BY THE COMMISSION: By letter dated November 13, 1992, from Carl Daniel, Vice President, Carolina Water Service, Inc. of North Carolina (CWS), CWS seeks assistance and guidance in the selection of the appropriately sized elevated storage tank for the Cambridge Subdivision. The CWS letter requests assistance as to the proper sized tank for this area to (a) avoid the need to install a second tank at a later date, and (b) avoid any excess capacity adjustment.

Such letter was directed to Commission Staff Engineer Rudy Shaw and has subsequently been placed in the above docket for disposition.

On November 19, 1992, the Public Staff filed a response to the letter from CWS.

In its response, the Public Staff states that it is not appropriate for the Commission to make management decisions about plant expansion; that CWS appears to be seeking Commission pre-approval for its future elevated storage tank which is not the traditional procedure under the Commission's regulatory framework; and that while it may benefit a utility to get regulatory pre-approval of all projects, this would involve the Commission and intervenors in utility operations at a level of detail that is neither feasible nor appropriate.

Further, the Public Staff states that it would be appropriate for the Commission to require CWS (and all utilities) to file formal applications or petitions with the Chief Clerk in similar circumstances in the future, rather than being directed to a Commission Staff member.

As the Commission concluded in its decisions in the last two general rate cases for CWS, a capacity allowance in the amount of 35 percent was provided to take into consideration engineering, construction, and maintenance efficiencies which are inherent in meeting reasonably anticipated growth. As pointed out by the Public Staff in its response, it is possible that the prudent decision for CWS is to install a large size tank initially, because that is the least cost approach in the long term analysis. However, it is also possible that not all of the tank may not be used and useful in the early years of its life as was the case in certain instances in the last two CWS rate case proceedings.

The Commission declines to advise CWS as to the specific size of elevated storage facilities to install for the Cambridge Subdivision. The decision in question is one which should be made by utility managers utilizing their business expertise and relevant knowledge of regulatory policies adopted by the Commission. As the Commission said in its Order dated September 11, 1992, in Docket No. W-100, Sub 13, the Commission expects utilities under its jurisdiction to be operated in an economically efficient and prudent manner. In so doing, the Commission recognizes management's responsibility to provide for expansion in a prudent manner using a least cost approach while also considering certain financing options, including contributions in aid of construction or advances in aid of construction.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby declines to advise CWS as to the specific size of elevated storage facilities to install for the Cambridge Subdivision for the reasons set forth hereinabove.

2. That if similar situations occur in the future whereby CWS seeks requests of this nature, they should be filed in the form of a petition and directed to the Office of the Chief Clerk.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of January 1992.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Commissioners Sarah Lindsay Tate and Charles H. Hughes dissent.

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G-21, Sub 284 (5-26-93)

North Carolina Natural Gas Corporation - Order Closing Docket in Complaint of Runnymede Mills, Inc.
G-21, Sub 285 (5-26-93)

Piedmont Natural Gas Company - Order Closing Docket in Complaint of Sapona Manufacturing Company, Inc.
G-9, Sub 301 (5-26-93)

Piedmont Natural Gas Company, Inc. - Order Closing Docket in Complaint of Howard L. Martin
G-9, Sub 307 (1-6-93)

Piedmont Natural Gas Company, Inc. - Order Dismissing Complaint of William E. Carrico
G-9, Sub 341 (12-10-93)

Public Service Company of North Carolina, Inc. - Order Giving Notice of Intent to Close Docket in Complaint of The Slosman Corporation
G-5, Sub 254 (11-12-93)

Public Service Company of North Carolina, Inc. - Order Giving Notice of Intention to Close Docket in Complaint of Gerber Products Company
G-5, Sub 287 (5-26-93)

Public Service Company of North Carolina, Inc. - Order Regarding Proposed Orders in Complaint of Selee Corporation
G-5, Sub 291 (10-7-93)

Public Service Company of North Carolina, Inc. - Recommended Order Denying Complaint of Harold L. Barndt
G-5, Sub 312 (6-3-93)

EXPLORATION AND DEVELOPMENT - Order Approving E and D Refund Plan

Company	Docket Number	Date
North Carolina Natural Gas Corporation	G-21, Sub 317	4-7-93
Pennsylvania and Southern Gas Company	G-3, Sub 177	4-7-93
Piedmont Natural Gas Company, Inc.	G-9, Sub 337	3-30-93
Public Service Company of North Carolina, Inc.	G-5, Sub 314	3-30-93

RATES

North Carolina Natural Gas Corporation - Order Approving Refund
G-21, Sub 289 (4-28-93)

North Carolina Natural Gas Corporation - Order Allowing Rate Changes Effective November 1, 1993
G-21, Sub 315 (11-3-93)

North Carolina Natural Gas Corporation - Order Allowing Rate Reduction Effective March 1, 1993
G-21, Sub 316 (3-2-93)

North Carolina Natural Gas Corporation - Order Allowing Rate Adjustment Effective May 1, 1993
G-21, Sub 319 (5-5-93)

Pennsylvania & Southern Gas Company, North Carolina Gas Service Division - Order Approving Depreciation Rates
G-3, Sub 176 (2-16-93)

Pennsylvania and Southern Gas Company, North Carolina Gas Service Division - Order Granting Motion to Amend the Record
G-3, Sub 178; G-3, Sub 180 (10-18-93)

Piedmont Natural Gas Company, Inc. - Order Suspending Proposed Rates
G-9, Sub 340 (9-22-93)

Piedmont Natural Gas Company, Inc. - Order Denying Deferral Accounting Treatment and Denying Interim Rates (Commissioners Cobb and Hughes dissent as to the denial of interim rate relief.)
G-9, Sub 340 (10-1-93)

Piedmont Natural Gas Company, Inc. - Order Allowing Rate Increase Effective October 1, 1993
G-9, Sub 342 (10-5-93)

Public Service Company of North Carolina, Inc. - Order Allowing Rate Reduction Effective February 1, 1993
G-5, Sub 313 (2-2-93)

Public Service Company of North Carolina, Inc. - Order Allowing Rate Changes Effective May 1, 1993
G-5, Sub 316 (5-5-93)

SECURITIES

North Carolina Natural Gas Corporation - Order Granting Authority to Issue and Sell 825,000 Shares of Common Stock
G-21, Sub 313 (1-27-93)

Piedmont Natural Gas Company, Inc. - Order Granting Authority to Issue and Sell Debt Securities
G-9, Sub 335 (4-15-93)

Piedmont Natural Gas Company, Inc. - Order Approving Issuance of Additional Shares of Piedmont Natural Gas Company, Inc., Common Stock
G-9, Sub 336 (2-23-93)

TARIFF

Pennsylvania and Southern Gas Company, North Carolina Gas Service Division - Order Approving Tariff Filings
G-3, Sub 178; G-3, Sub 180 (12-29-93)

Public Service Company of North Carolina, Inc. - Order Allowing Tariff Filing to Become Effective and Requiring Annual Reports
G-5, Sub 310 (1-14-93)

Public Service Company of North Carolina, Inc. - Order Allowing Tariff Filing to Become Effective and Requiring Annual Reports
G-5, Sub 323 (11-30-93)

MISCELLANEOUS

Pennsylvania and Southern Gas Company, North Carolina Gas Service Division - Order Approving Notice
G-3, Sub 178; G-3, Sub 180 (12-30-93)

Piedmont Natural Gas Company, Inc. - Order Denying Reconsideration of SFAS 106 Ratemaking Treatment or, in the Alternative, for a General Increase in Its Rates and Charges
G-9, Sub 340 (11-3-93)

Public Service Company of North Carolina, Inc. - Order on Refund Plan (Commissioner Hughes concurs in separate opinion.)
G-5, Sub 279 (9-10-93)

Public Service Company of North Carolina, Inc. - Order Denying Deferral Accounting Treatment and Dismissing Petition
G-5, Sub 319 (9-30-93)

Public Service Company of North Carolina, Inc. - Order Allowing Cross-Over of Franchised Territory
G-5, Sub 321 (8-17-93)

MOTOR BUSES

AUTHORITY GRANTED - COMMON CARRIER

Company	Charter Operations	Docket No.	Date
A.M.A. Tours Unlimited, Alphonso Haigler and Mary L. Haigler, d/b/a	Statewide	B-594	10-14-93
Cape Fear Coach Lines, Inc.	Statewide	B-591	11-1-93
Electric City Shuttle Service P. Douglas McAlister, d/b/a	Statewide	B-589	10-27-93
Elite Charter Service, L.R.N. Enterprises, Inc., d/b/a	Statewide	B-584	4-8-93
Five Star Tours, Beeling Carriers, Inc., d/b/a	Statewide	B-585	6-18-93
H. & S. Tours, Incorporated	Statewide	B-593	12-9-93
Harris Charter, Ronald L. Harris, d/b/a	Statewide	B-590	10-19-93
Highway Express Tours, Larry Best and Lawrence Lennon, d/b/a	Statewide	B-556	4-22-93
Horton's Transit Service Lenon J. Horton and Larry E Horton, d/b/a	Statewide	B-537	1-21-93
J.N.M., Inc.	Statewide	B-596	12-20-93
Kirk Transportation, Inc.	Statewide	B-595	12-20-93
The Beach Bus, Inc.	Statewide	B-588	10-13-93

Yellow Cab Co. of Charlotte, Inc.	Statewide	B-592	12-9-93

AUTHORIZED SUSPENSION

Company	Certificate	Reason
Cherokee KOA, Sontag, Inc., d/b/a	B-532, Sub 2	Good Cause
Ernest & Claudia Nettles Tours, Ernest & Claudia Nettles, d/b/a	B-580, Sub 2	Good Cause

BROKER'S LICENSE - (GRANTING AND CANCELLING)

Country Cottage Tours, Sylvia Strickland and Kenneth Strickland, Sr., d/b/a - Order Cancelling Broker's License No. B-373
B-373, Sub 2 (3-9-93)

Express Tours, Loretta M. Harrison, d/b/a - Order Cancelling Broker's License No. B-417
B-417, Sub 1 (1-13-93)

Helper Tours, H. M. Helper, d/b/a - Recommended Order Cancelling Broker's License No. B-395
B-395, Sub 1 (5-19-93)

Jones Tours, Charles William Jones and Betty Holt Jones - Order Granting Broker's License No. B-579
B-579 (1-26-93)

Specialty Tours, Vickie J. Ensley, d/b/a - Order Granting Borker's License No. 587
B-587 (11-15-93)

Travel Masters of New Bern, Inc. - Order Cancelling Broker's License No. B-499
B-499, Sub 2 (3-9-93)

CERTIFICATES CANCELLED

Carolina Transit Lines of Charlotte, Inc. - Order Cancelling Certificate No. B-295 - Ceased Operations
B-295, Sub 9 (3-17-93)

Council Coach Service, Willie James Clark, d/b/a - Recommended Order Cancelling Temporary Operating Authority Certificate No. B-586 - Termination of Liability Insurance Coverage
B-586, Sub 1 (10-27-93)

Gary's Travel Tours, Gary's Charter, Inc., d/b/a - Recommended Order Cancelling Operating Authority Certificate No. B-540 - Termination of Liability Insurance Coverage
B-540, Sub 1 (2-22-93)

ORDERS AND DECISIONS LISTED

Highland Tour and Charter, Inc. - Order Cancelling Certificate No. B-484 - Ceased Operations
B-484, Sub 1 (8-26-93)

Tar Heel Stage Lines, Inc. - Order Cancelling Certificate No. B-531 - Ceased Operations
B-531, Sub 3 (10-14-93)

UBAM Travel & Tours, Inc. - Recommended Order Cancelling Operating Authority Certificate No. B-559 - Termination of Liability Insurance Coverage
B-559, Sub 3 (10-13-93)

COMPLAINTS

Piedmont Coach Lines - Order Tentatively Concluding No Good Cause to Investigate Complaint of Jarrett Webb, III
B-110, Sub 27 (10-26-93)

Piedmont Coach Lines - Order Finding no Reasonable Grounds to Proceed with Complaint and Closing Docket of Jarrett Webb III
B-110, Sub 27 (11-23-93)

NAME CHANGE

Bates, Peggy Tours and Conventions, Peggy B. Bates, d/b/a - Order Approving Name Change
B-600 (12-21-93)

C & E Charter & Tours Co. - Order Approving Name Change from Artis Robert Ezzell, Jr., and James Philip Canterbury, d/b/a C & E Charter and Tours
B-520, Sub 1 (1-25-93) Errata Order (2-11-93)

Summey Travel Services, Inc. - Order Approving Name Change from Long's Travel Agency, Inc., Division of Long's of Rockingham
B-598 (11-29-93)

MOTOR TRUCKS

APPLICATIONS AMENDED

ASAP Couriers, Sherry Jo Amyotte, d/b/a - Order Amending Application, Allowing Withdrawal of Protests, and Cancelling Hearing
T-3740 (1-6-93)

Anytime Express, Michael E. Medley, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3739 (1-12-93)

Bost, R. Wayne Trucking, Inc. - Order Amending Application and Cancelling Hearing
T-3847 (7-29-93)

ORDERS AND DECISIONS LISTED

Dependable Tank Lines, Inc. - Order Amending Contract Carrier Authority Permit No. P-475
T-2421, Sub 1 (7-9-93)

DuBose Transportation Services, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3914 (12-30-93)

East Coast Transport Company, Inc. - Order Amending Contract Carrier Authority
T-342, Sub 10 (9-10-93)

East Coast Transport Company, Inc. - Order Amending Application and Cancelling Hearing
T-342, Sub 11 (10-20-93)

Edwards, J. M. Trucking Co., Jerry M. Edwards, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3742 (1-11-93)

Farmer, Bobby Gene - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3790 (3-31-93)

Fox, Elmer Leon - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3832 (7-8-93)

Frito-Lay, Inc. - Order Amending Contract Carrier Authority Certificate/Permit No. CP-120
T-2630, Sub 4 (1-13-93)

Graves, Bennie Hubert Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3769 (2-24-93)

Lovette Company, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-2415, Sub 1 (1-21-93)

Men on the Move, Rodrick Malcolm Hudgins, III and Nicholas Boyd Seymour, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3771 (3-4-93)

Miller's Mobile Home Moving, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3743 (1-8-93)

Mountain River Trucking Company, Inc. - Order Amending Contract Carrier Authority
T-2701, Sub I (11-24-93)

ORDERS AND DECISIONS LISTED

Pearson & Purvis Enterprises, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3772 (3-2-93)

Ryder Dedicated Logistics, Inc. - Order Amending Contract Carrier Authority
T-3781, Sub 2 (2-26-93)

Sam's Pick-Up/Delivery Service, Samuel C. White, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3780 (4-6-93)

Save-Time Courier, Sylvia S. Jordan, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3404, Sub 1 (3-17-93)

Schwerman Trucking Co. of Va., Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3748 (2-11-93)

Stat Delivery Systems, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3918 (12-30-93)

Stephens Trucking, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3764 (2-24-93)

Superior Carriers, Inc. - Order Amending Application and Cancelling Hearing
T-3886 (10-20-93)

Suttles Truck Leasing, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3812 (5-28-93)

TBT Corp. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3749 (1-27-93)

Tarte's Express Trucking, Jimmie Merkson Tarte, d/b/a - Order Amending Application and Allowing Withdrawal of Protest
T-3775 (3-29-93)

The Webb Company, Darrell D. Webb, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3903 (12-28-93)

Warren Trucking, Charles C. Warren, Jr., d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3913 (12-30-93)

ORDERS AND DECISIONS LISTED

APPLICATIONS DENIED/DISMISSED

A & A Express Delivery, Ronald D. Atkins and Karen L. Atkins, d/b/a - Recommended Order Denying Application
T-3773 (3-18-93)

L & L Transport, Leroy T. Viars, d/b/a - Recommended Order Dismissing Application
T-3797 (5-26-93)

Louderback Transportation Company of Delaware - Recommended Order Dismissing Application for Sale Transfer of Certificate No. C-654 from Advantage Moving and Storage Services, Inc.
T-3762 (9-17-93)

MJ Transport, Michael Jodean Jones, d/b/a - Recommended Order Dismissing Application
T-3808 (11-24-93)

Party Reflections, Inc. - Recommended Order Dismissing Application
T-3738 (1-8-93)

Running Man Courier Service, Kenneth Earl White, d/b/a - Recommended Order Dismissing Application
T-3836 (7-29-93)

Tarte's Express Trucking, Jimmy Merkson Tarte, d/b/a - Recommended Order Dismissing Application
T-3775 (4-6-93)

APPLICATIONS WITHDRAWN (COMMON OR CONTRACT CARRIER AUTHORITY)

Company	Docket Number	Date
ASAP Couriers, Sherry Jo Amyotte, d/b/a	T-3740	8-25-93
Break Bulk & Packaging Co., Inc.	T-3828	5-28-93
Corporate Moving Systems, Inc.	T-3712	1-25-93
Hallmart Distributors, Inc.	T-3694, Sub 1	1-20-93
Johnny's Wrecker Service, Johnny Hicks, d/b/a	T-3774	4-21-93
Liberty Transportation, Inc.	T-3875	11-8-93
Morgan Trucking, Inc.	T-2166, Sub 8	8-24-93
PTC of Mt. Airy, Inc.	T-3736	6-9-93
Ryder Dedicated Logistics, Inc.	T-3781, Sub 3	8-23-93
Winston Trucking Company	T-3852, Sub 1	8-11-93

AUTHORITY GRANTED - COMMON CARRIER

Anytime Express, Michael E. Medley, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3739 (3-5-93)

ORDERS AND DECISIONS LISTED

B & J Mobile Home Movers, Billy Tew and Johnny Tew, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3765 (3-19-93)

Bestway Mobile Home Service, Gordon Lee Best and Leland L. Lawrence, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Manufactured Houses, Modular Homes, and Office Trailers, Statewide
T-3817 (5-26-93)

Bost, R. Wayne Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Commodities in Bulk, in Tank Vehicles; Except Petroleum and Petroleum Products and Liquid Asphalt; Statewide
T-3847 (10-13-93)

Brannock Trucking, Brad Brannock, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3853 (9-27-93)

Braswell Trucking, Daniel Braswell, d/b/a - Order Granting Common Carrier Authority to Transport Group 5, Solid Refrigerated Products, from Mt. Olive to Points in North Carolina
T-3734 (2-12-93)

Brookshire Express Services, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk and Unmanufactured Tobacco, Statewide (Note: The authority granted herein, to the extent it duplicates any existing authority, shall not be construed as conveying more than one operating right.)
T-2460, Sub 3 (1-22-93)

Brown's Mobile Home Service, Warren Ray Brown, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Manufactured Homes, Between Points in the Counties of Lee, Harnett, Moore, Chatham, Alamance, Wake, Cumberland, Johnston, Sampson, Brunswick, New Hanover, Orange, Robeson, and Guilford
T-3752 (3-29-93)

Bryant's Trucking, Hezekiah Bryant, Jr., d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes and Mobile Offices, Statewide
T-3755 (2-12-93)

Bryson Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3737 (4-21-93)

Burlington Motor Carriers, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3789 (6-14-93)

Cauble, Charlie Construction, Charles D. Cauble, d/b/a - Recommended Order Granting Common Carrier Authority to Transport Group 21, Trailers and Office Trailers, Statewide
T-3807 (8-4-93)

Certus, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Chemicals in Bulk, Statewide
T-3759 (3-5-93)

Chapel Hill Maintenance, Chapel Hill Grounds Maintenance, Inc., d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3801 (7-23-93)

Combined Transportation Services, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3575 (8-17-93)

Corriher Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Classes A and B Explosives and Unmanufactured Tobacco and Accessories); Group 2, Heavy Commodities; Group 10, Building Materials; and Group 14, Dump Truck Operations; Statewide
T-3698 (9-14-93)

Cozy Cove Mobile Home & R.V. Specialists, Robert R. St. Mary, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, from Henderson County to Points and Places West of and Including Mecklenburg, Rowan, Iredell, Alexander, Wilkes, and Alleghany Counties, and from these Points and Places back to Henderson County
T-3648 (2-26-93)

Cranston Trucking Company Division of Cranston Print Works Company - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3881 (12-9-93)

Crawford Deliveries, Bernard Crawford, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-2290, Sub 1 (10-18-93)

Dial Four Delivery, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Between Points in North Carolina West of and Including the Counties of Caswell, Alamance, Chatham, Moore, and Richmond (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3567 (8-31-93)

Direct Delivery Service, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3763 (7-19-93)

Farmer, Bobby Gene - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, from Ashe County to Points in North Carolina and from Points in North Carolina to Ashe County (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not authorized.)
T-3790 (4-21-93)

Forbes Transfer Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco and Accessories, Statewide (NOTE: The operating authority granted herein, to the extent it duplicates any existing authority, shall not be construed as conveying more than one operating right.)
T-247, Sub 12 (6-14-93)

Foremost Freight, Inc. - Order Granting Common Carrier Authority to Transport Group 10, Building Materials, Statewide
T-3799 (5-5-93)

Fox, Elmer Leon - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Between Points in Buncombe, Haywood, Henderson, Polk, Madison, McDowell, Yancey, Rutherford, Burke, Transylvania, Swain, Clay, Macon, Jackson, Cherokee, Graham, Cleveland, and Gaston Counties
T-3832 (7-30-93)

FWC, Incorporated - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3690 (10-7-93)

G. B. Truck'n, Robert Glenn Brewer, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation and Accessories, is not Authorized.)
T-3642 (6-7-93)

G & S Towing, Walter Lee Starnes, Jr., d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Between Points in Union and Anson Counties, and from Points in Union and Anson Counties to all Points in North Carolina, and from all Points in North Carolina back to Union and Anson Counties
T-3727 (1-29-93)

General Parcel Service, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles, Statewide
T-3815 (8-5-93)

Glen's Moving & Storage, Miland Glen Jackson, d/b/a - Order Granting Common Carrier Authority to Transport Group 18, Household Goods, Statewide
T-3768 (5-26-93)

ORDERS AND DECISIONS LISTED

Glu-Lam Transport, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Structural Components, Gazebos, Playground, and Park Products, from Wake County to Points in North Carolina, and from Points in North Carolina to Wake County
T-3776 (4-23-93)

Gophers Personal Delivery Service, Daniel D. Thomas, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3696 (9-1-93)

Heartland Express, Inc., of Iowa - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3843 (9-15-93)

Hendrix, T. M. Trucking, Thomas Michael Hendrix, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, and Group 17, Textile Mill Goods and Supplies, Statewide
T-3845 (11-3-93)

Henry, C. S. Transfer, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk and Unmanufactured Tobacco and Accessories, Statewide
T-293, Sub 4 (3-5-93)

Herman Bros., Inc. - Recommended Order Approving Application for Common Carrier Authority to Transport Group 10, Building Materials, Statewide
T-2021, Sub 4 (4-2-93)

Hester Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3831 (8-9-93)

Jamerson Brothers Trucking Co., Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Commodities in Bulk; Group 2, Heavy Commodities; and Group 10, Building Materials, Statewide
T-3732 (2-11-93)

Jenkins, Columbus Trucking, Columbus Jenkins, d/b/a - Order Granting Common Carrier Authority to Transport Group 7, Cotton in Bales, Statewide
T-3644, Sub 2 (10-7-93)

Johnson, Darrell Keith - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, from Onslow County to Points in Onslow, Pender, Duplin, and Jones Counties
T-3869 (10-18-93)

Johnson Transport, David Paul Johnson, d/b/a - Order Granting Common Carrier Authority to Transport Group 10, Building Materials, from Guilford County to Points in North Carolina
T-3782 (4-12-93)

King, D. R. Mobile Home Services, Donnie R. King, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes and Mobile Homes Supplies, Statewide
T-3754 (4-8-93)

L.T.D.I., Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3851 (10-1-93)

Lattavo Brothers, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco; and Group 2, Heavy Commodities, Statewide
T-3767 (11-3-93)

Lovette Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, and Group 5, Solid Refrigerated Products, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories is not Authorized.)
T-2415, Sub 1 (1-27-93)

M & F Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles, Statewide
T-3833 (10-29-93)

M.S. Carriers, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3504, Sub 1 (4-1-93)

Mako Transportation, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Group 10, Building Materials; and Group 14, Dump Truck Operations, Statewide
T-3513, Sub 3 (3-9-93)

Martin, W. M. Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except those Requiring Special Equipment and Except Unmanufactured Tobacco, Over Irregular Routes, Statewide
T-653, Sub 9 (6-21-93)

Merritt Trucking Company, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Crude and Refined Vegetable Oils and By-Products of the Refining Process, in Bulk in Tank Trucks, Statewide
T-2143, Sub 25 (11-22-93)

Miller's Mobile Home Moving, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Between Points in Surry, Wilkes, Alleghany, Stokes, and Yadkin Counties
T-3743 (2-5-93)

Moore, H. H., Jr., Trucking Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco; and Group 2, Heavy Commodities, Statewide
T-3760 (4-26-93)

Morgan, R. L. Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk, from Buncombe and Mecklenburg Counties to Points in North Carolina, and from Points in North Carolina to Buncombe and Mecklenburg Counties; and Group 17, Textile Mill Goods and Supplies, from Buncombe County to Points in North Carolina, and from Points in North Carolina to Buncombe County
T-3733, Sub 1 (12-30-93)

New Dixie Transportation Corp. - Order Granting Common Carrier Authority to Transport Group 21, Chemicals in Bulk, (Except Gasoline, Kerosene, Fuel Oils, and Liquified Petroleum Gas), Statewide
T-3573, Sub 1 (8-11-93)

North Bergen REX Transport, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3791 (4-28-93)

North-South Courier, North-South Group, Incorporated, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3750 (6-24-93)

Omni Transport, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide; Group 2, Heavy Commodities, and Group 10, Building Materials, from Granville County to Points in North Carolina; and Group 13, Motor Vehicles, from Onslow and New Hanover Counties to Points in North Carolina
T-3849 (9-30-93)

PST Vans, Inc., Norton Enterprises, Inc., d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3741 (3-9-93)

PTC of Mt. Airy, Inc. - Recommended Order Granting Application for Common Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid, in Bulk in Tank Trucks; and Group 21, Asphalt and Asphalt Products, Including Cutback and Emulsions, in Bulk in Tank Trucks, Statewide
T-3736, Sub 1 (4-6-93) Errata Order (6-10-93)

Pearidge Transport, Donald C. Adams, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3753 (1-28-93)

Pearson & Purvis Enterprises, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, for Rowan County to all Points in North Carolina and from all Points in North Carolina to Rowan County
T-3772 (3-29-93)

Pierce, B. B. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3745 (4-8-93)

Pro Express, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, from Raleigh to Durham, Chapel Hill, Hillsborough, Burlington, Graham, Greensboro, Winston-Salem, and from this Cities back to Raleigh
T-3874 (10-18-93)

Puryear Transport, Inc. - Recommended Order Granting Application, in Part for Common Carrier Authority to Transport Group 21, Specification No. 2 Oil, in Bulk, in Tank Trucks, from Lee County to all Points in North Carolina
T-2689, Sub 6 (12-6-93)

Quick & Easy Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3854 (8-19-93)

RJ and Son Transport, Randy Eugene Josey, d/b/a - Recommended Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3826 (7-28-93)

Raleigh Road Box Co., Charlie Moses Smith, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories; and Group 10, Building Materials, from Vance and Granville Counties to Points in North Carolina
T-3609 (7-8-93)

Raven Transport Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3702 (1-11-93)

Red Express, James & Phyllis Conley, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Blood Products and Pharmaceutical Products, Statewide
T-3800 (5-12-93)

Royal Express, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Commodities in Bulk, Statewide
T-3787 (7-22-93)

Same Day Delivery, Mark Koehler, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3822 (9-24-93)

Shea Transport, Wayne Christian, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Beer, Wine, and Soft Drink Products, Statewide
T-3794 (6-1-93)

Sherrill Mobile Home Mover, Robert Maurice Sherrill, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3880 (12-6-93)

Sigmon, Gene Stuart - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3861 (12-9-93)

SNYDER Mobile Home Transport, John Snyder & Randy Snyder, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3821 (8-10-93)

Southern Bulk Haulers, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Cement, Cement Products, and Fly Ash, Statewide (NOTE: The Authority Granted herein, to the Extent it Duplicates any Authority Currently Held, Shall Not Be Construed as Conveying More than One Operating Right.)
T-2924, Sub 1 (8-25-93)

Spain's Pre-Owned Mobile Homes, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, from Pitt and Wilson Counties to all Points in the State of North Carolina, and from all Points in the State of North Carolina Back to Pitt and Wilson Counties
T-3725, Sub 1 (3-9-93)

Stephens, Daniel Edward - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Between Points and Places West of and Including the Counties of Union, Cabarrus, Rowan and Davie, Yadkin, and Surry
T-2095, Sub 2 (10-14-93)

Stephens Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3764 (4-1-93)

Superior Carriers, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Liquid Chemicals in Bulk; Excluding Liquid Asphalt, Gasoline, Fuel Oils, Distillates, Lubricating Oils, Kerosene, and White Oils; Statewide
T-3886 (11-22-93)

TBT Corp. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, from Davidson and Randolph Counties to all Points in North Carolina, and from all Points in North Carolina to Davidson and Randolph Counties (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)

Taylor's Mobile Home Service, James D. Taylor, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, in Wayne, Lenoir, Jones, Onslow, Duplin, Sampson, Bladen, New Hanover, Brunswick, and Columbus Counties
T-2992, Sub 3 (5-3-93)

The Observer Transportation Company - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide, Restricted Against the Transportation of any Package or Article Weighing more than 150 Points or Exceeding 20 Cubic Feet in Volume, and Each Package or Article shall be Considered as a Separate and Distinct Shipment
T-107, Sub 2 (8-19-93)

Turner Trucking Company - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3778 (5-25-93)

W & R Services, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3700 (1-29-93)

Walker's Express, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide
T-3893 (12-6-93)

West's Durham Transfer & Storage, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Commodities in Bulk, from Wake and Durham Counties to All Points in North Carolina
T-1865, Sub 3 (4-8-93)

York Transportation, Inc. - Order Granting Common Carrier Authority to Transport Group I, General Commodities, Statewide
T-3872 (10-29-93)

AUTHORITY GRANTED - CONTRACT CARRIER

Alexander's Delivery Service, Rufus D. Alexander, Sr., d/b/a - Order Granting Contract Carrier Authority to Transport Group I, General Commodities, within a 175-Mile Radius of Raleigh, North Carolina, Under Continuing Contract with Fisher Scientific
T-3855 (8-30-93)

ORDERS AND DECISIONS LISTED

All South Deliveries, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Sears, Roebuck and Co.
T-3858 (9-30-93)

B & S Enterprises, William T. Smith, d/b/a - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid, in Bulk in Tank Trucks, Statewide, Under Contract with Sprague Energy
T-3786 (11-16-93)

B-Unique Limited - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, from Winston-Salem to all Points in North Carolina Under Contract with Sun Chemical Corporation
T-3805 (5-26-93)

B-Unique Limited - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Sun Chemical Corporation
T-3805, Sub 1 (7-20-93)

Beasley, Mark - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Statewide, Under Contract with Adams Products Company
T-3894 (11-30-93)

Big K Oil Co. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Cascades Industries, Inc., and Laurel Hill Paper Co., Inc.
T-3865 (9-24-93) Errata Order (10-13-93)

Brookshire Express Services, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk and Unmanufactured Tobacco, Statewide, Under Continuing Contract with P.F.S., Inc.
T-2460, Sub 2 (2-11-93)

Carolina Public Warehouse, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, within the Counties of Forsyth, Stokes, Rockingham, Caswell, Guilford, Alamance, Orange, Durham, Wake, Surry, Yadkin, Davidson, Montgomery, Richmond, Scotland, Robeson, Columbus, Davie, Rowan, Cabarrus, Stanly, Union, Mecklenburg, Iredell, Catawba, Gaston, Cleveland, Burke, McDowell, Rutherford, Polk, and Henderson Under Continuing Contracts with Atlantic Paper Company, Dow Chemical USA, and Tervakoski Specialty Papers, Inc.
T-3568, Sub 1 (11-22-93)

Christie, Craig Lafayette - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Under Bilateral Contract with Adams Products Company, from its Plants Located in Durham, Kinston, Fayetteville, and Morrisville, North Carolina, to Points and Places Within the State of North Carolina and Return
T-1909, Sub 14 (2-1-93)

Cotten, H. L. - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Statewide, Under Continuing Contract with Adams Products Company
T-3884 (11-16-93)

Dixie Trucking Company, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities; Except Unmanufactured Tobacco and Accessories, Commodities in Bulk, and Motion Picture Film and Special Service; Statewide, Under Continuing Contracts with Sara Lee Corporation and Nordyne, Inc.
T-299, Sub 11 (4-1-93)

Estes Express Lines - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk Tank Vehicles and Unmanufactured Tobacco and Accessories, Statewide, Under Continuing Contract with Sara Lee Corporation
T-676, Sub 9 (3-25-93)

Ezzell Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Caterpillar, Inc.
T-1536, Sub 1 (10-13-93)

Fleetmaster Cartage, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, and Group 21, Aluminum Cans and Can Ends on Roller Bed Trailer Equipment, Statewide, Under Continuing Contract with Miller Brewing Company
T-3842 (8-25-93)

Floyd, Robert Lee - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Statewide, Under Contract with Adams Products Company
T-3867 (9-24-93)

Four Truckers, Inc. Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk, Statewide, Under Continuing Contract with ITT Corporation
T-3585, Sub 1 (8-23-93)

Grant & Holden, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide, Under Contract with Packaging Corporation of America
T-3746 (2-18-93)

Graves, Bennie Trucking, Bennie Hubert Graves, d/b/a - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, from Guilford County to Points in North Carolina, and from Points in North Carolina to Guilford County, Under Contract with Paper Stock Dealers, Inc. (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3769 (3-5-93)

Harrell, R. O., Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Salt, in Bulk in Tank Vehicles, Statewide, Under Continuing Contract with Cargill, Inc., Salt Division
T-2064, Sub 4 (9-10-93)

Henry, C. S. Transfer, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk and Unmanufactured Tobacco, Statewide, Under Continuing Contract with Food Lion, Inc.
T-293, Sub 5 (3-12-93)

Henry, C. S. Transfer, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Contract with Transportation Logistics of North Carolina, Inc.
T-293, Sub 6 (8-16-93)

Jackson, Monroe Trucking Company, Monroe Jackson, d/b/a - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Statewide, Under Contract with Adams Products Company
T-3863 (9-24-93)

JEM Transport, Inc. - Order Granting Contract Carrier Authority to Transport Group 5, Solid Refrigerated Products, Statewide, Under Continuing Contract with Fast Food Merchandisers, Inc.
T-3859 (12-15-93)

L & L Transport, Leroy T. Viars, d/b/a - Order Granting Contract Carriers Authority to Transport Group 1, General Commodities, Statewide, Under Contract with Insteel Wire Products
T-3797, Sub 1 (10-18-93)

Liquid Transporters, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Liquid Chemicals, in Bulk in Tank Vehicles, Statewide, Under Continuing Contract with Rohm and Haas Company
T-2229, Sub 5 (2-3-93)

MGM Transport Corporation - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Stanley Furniture Company, Inc.
T-2395, Sub 3 (11-22-93)

Melton Delivery, Francis Donald Melton, d/b/a - Order Granting Contract Carrier Authority to Transport Group 15, Retail Store Delivery Service, Between Points within a 25-Mile Radius of Shelby, North Carolina, Under Continuing Contract with Sears Roebuck and Co.
T-3824 (8-11-93)

Merchants Home Delivery Service, Inc. - Order Granting Contract Carrier Authority to Transport Group 15, Retail Store Delivery Service, from the Retail Stores or Warehouses of Rhodes, Inc., Located throughout North Carolina, to its Customers in North Carolina, and the Return or Exchange of Such Merchandise, Under Individual Bilateral Written Contract with Rhodes, Inc.
T-1655, Sub 3 (11-10-93)

ORDERS AND DECISIONS LISTED

Montgomery Tank Lines, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Industrial Chemicals, in Bulk, Statewide, Under Continuing Contract with Chemical Specialties Incorporated and Mineral Research and Development Corporation
T-3697, Sub 1 (7-29-93)

Morgan, R. L. Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Contract with Southeastern Container, Inc. (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3733 (1-6-93)

N & M Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Drexel Heritage Furnishings, Inc.
T-3811 (6-9-93)

Owen, Harry Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group I, General Commodities, Statewide, Under Continuing Contract with Dow Corning Corporation
T-3840 (8-11-93)

Pearce, James R. Trucking, James R. Pearce, d/b/a - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Statewide, Under Continuing Contract with Adams Products Company
T-3788 (3-19-93)

Pemberton Truck Lines, Inc. - Order Granting Contract Carrier Authority to Transport Group 16, Furniture Factory Goods and Supplies, Statewide, Under Contract with Heilig Meyers Furniture Co.
T-3793 (5-3-93)

Pollard, Donald Myatt - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Under Bilateral Contract with Adams Products Company, from its Plants Located in Durham, Rocky Mount, Wilmington, Kinston, Fayetteville, and Morrisville, North Carolina, to Points and Places within the State of North Carolina, and Return
T-3819 (5-20-93)

Russell, Darl - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Under Bilateral Contract with Adams Products Company, from its Plants located in Durham, Rocky Mount, Wilmington, Kinston, Fayetteville,and Morrisville, North Carolina, to Points and Places within the State of North Carolina and Return
T-3798 (8-5-93)

Ryder Dedicated Logistics, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide, Under Continuing Contract with Zellerbach, a Division of Mead Corporation
T-3781, Sub 1 (5-25-93)

Ryder Dedicated Logistics, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Radiator Specialty Company
T-3781, Sub 5 (10-27-93)

Ryder Dedicated Logistics, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Continuing Contract with Camden Wire Co., Inc.
T-3781, Sub 6 (10-14-93)

Ryder Distribution Resources, Inc. (now Ryder Dedicated Logistics, Inc.) - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide, Under Continuing Contract with P. H. Glatfelter Company
T-2302, Sub 11 (3-12-93)

Scales Transport Corp. - Order Granting Contract Carrier Authority to Transport Group 21, Glass Containers and Equipment, Materials, and Supplies used in the Manufacture and Distribution thereof, Between all Points in North Carolina, Under Continuing Contract with American National Can Company
T-3818 (7-20-93)

Schneider National Carriers, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Between Points in North Carolina, Under Contract with Georgia-Pacific Corporation
T-3182, Sub 1 (11-30-93)

Schneider Specialized Carriers, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Heat Exchangers or Equalizers for Gases or Liquids; Machinery and Equipment for Washing, Heating, Cooling, Conditioning, Humidifying, Dehumidifying, and Moving of Gases or Liquids; and Parts, Attachments, and Accessories, for use in the Installation and Operation of the Commodities Described Herein, Statewide, under Continuing Contract with the Trane Company
T-3266, Sub 2 (8-30-93)

Schwerman Trucking Co. of Va., Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Cement in Bulk and in Packages, Statewide, Under Continuing Contracts with Carolinas Cement Company L.P.; d/b/a Roanoke Cement Company
T-3748 (4-26-93)

Seanor Trucking Company, Edward L. Seanor, d/b/a - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, and Group 17, Textile Mill Goods and Supplies, Statewide, Under Continuing Contract with North Carolina Farm Bureau Service Company, Incorporated; Americal Corporation; Spencer Gifts, Inc.; Exide Electronics; and ERJ deBaron, Inc.
T-3876 (10-28-93)

ORDERS AND DECISIONS LISTED

Sig's Express, Henry Allen Sigmon, d/b/a - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories; and Group 7, Cotton in Bales, Statewide under Continuing Contracts with Carris Reels, N. C., Inc., James Austin Company, and Carolina Truck Brokers, Inc.
T-3747 (3-5-93)

Suttles Truck Leasing, Inc. - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid, in Bulk in Tank Trucks; and Group 21, Chemicals, in Bulk in Tank Trucks, Statewide, Under Continuing Contracts with Worth Chemical and Georgia Pacific Corporation
T-3812 (7-22-93)

AUTHORIZED SUSPENSION

Company	Certificate	Reason
Advantage Moving and Storage Services, Inc. T-3578, Sub 1 (1-26-93)	C-654	Good Cause
Atlantic Oil Service, Inc. T-1703, Sub 4 (11-18-93)	P-259	Good Cause
Autofix Corporation T-3203, Sub 1 (3-26-93)	C-1763	Good Cause
Blount Transit, Inc. T-2631, Sub 2 (4-1-93)	CP-94	Good Cause
Bozovich Movers, Archie Thomas Bozovich, d/b/a T-3439, Sub 1 (6-9-93)	C-1887	Good Cause
Brubaker Transfer, Inc. T-3145, Sub 1 (7-29-93)	C-1760	Good Cause
Burgess, William Wayne T-2887, Sub 1 (4-16-93)	C-1801	Good Cause
Burks Moving & Storage, Inc. T-2020, Sub 3 (3-25-93)	C-710	Good Cause
Carmac Transport, Inc. T-3082, Sub 1 (3-2-93)	C-1673	Good Cause
Central Division, Inc. T-3234, Sub 1 (6-17-93)	C-1773	Good Cause
Chestnut Enterprises Trucking, Wilmington Shipping Company, d/b/a	C-1601	Good Cause

ORDERS AND DECISIONS LISTED

Council's Mobile Movers, Inc. T-3770 (1-15-93)	C-971	Good Cause
Cummings Mobile Home Services, C. L. Cummings, d/b/a T-3253, Sub 1 (10-18-93)	C-1799	Good Cause
Custom Transport, Inc. T-569, Sub 8 (3-3-93)	C-438	Good Cause
Cutler Trucking, Inc. T-3481, Sub 2 (4-15-93)	C-1902	Good Cause
D & R Services, Donald Revels, d/b/a T-3482, Sub 2 (4-7-93)	CP-122	Good Cause
DeLoatch Transportation, Inc. T-2675, Sub 1 (1-19-93)	C-1450	Good Cause
Direct Delivery Services, Inc. T-3763, Sub 1 (11-19-93)	C-2076	Good Cause
Ennis Heavy Equipment Rentals & Sales Edwin I. Ennis, Jr., d/b/a T-3553, Sub 1 (3-23-93)	C-1944	Good Cause
Hollowell Transportation Company T-1389, Sub 4 (6-9-93)	C-942	Good Cause
Jack's Mobile Home Service, Moses Lott Buffkin, d/b/a T-1511, Sub 5 (7-20-93)	C-981	Good Cause
Landmark Mobile Homes, Inc. T-2918, Sub 2 (5-26-93)	C-1429	Good Cause
Louisiana-Pacific Trucking Company T-2249, Sub 6 (12-10-93)	P-419	Good Cause
Lumberton Masonary Company T-2518, Sub 9 (11-22-93)	C-1345	Good Cause
Macon, Robert L. T-1486, Sub 3 (5-7-93)	P-496	Good Cause
Mid-State Moving Company, Inc. T-3271, Sub 3 (6-24-93)	C-677	Good Cause
N. C. Transport, Inc. T-1831, Sub 3 (7-19-93)	C-124	Good Cause

Neuse Transport, Incorporated T-2171, Sub 5 (12-9-93)	C-1176	Good Cause
Pippin, Herbert Joel T-2649, Sub 3 (12-2-93)	C-1410	Good Cause
Southern Container Corporation T-2981, Sub 1 (7-9-93)	C-1636	Good Cause
Standard Trucking Company T-315, Sub 6 (8-19-93)	C-356	Good Cause
Tri-State Moving & Storage, Joseph J. Afonso, d/b/a T-2498, Sub 4 (7-7-93)	C-1342	Good Cause
Wade Transportation Company, Inc. T-3608, Sub 1 (12-21-93)	P-626	Good Cause

CERTIFICATES/PERMITS CANCELLED

Ceased Operations

Company and Certificate No.	Docket Number	Date
Alexander Crane Service, Inc. (C-1897)	T-3470, Sub 2	5-26-93
Black Trucking Company, Inc. (C-1526)	T-2836, Sub 6	4-19-93
Brothers Mobile Home Movers, Tanny J. Woodell and John R. Woodell, d/b/a (CP-104)	T-2906, Sub 3	12-9-93
Brytran, Inc. (C-242)	T-2923, Sub 1	1-5-93
CSC Erectors, Inc. (P-166)	T-2102, Sub 3	11-3-93
Caustic Soda Transportation Co. (CP-32)	T-32, Sub 8	4-20-93
Chatham Trucking Company, Chatham Steel Corporation, d/b/a (C-1431)	T-2615, Sub 1	9-13-93
Cozy Cove Mobile Home & R.V. Specialists, Robert R. St. Mary, d/b/a (C-2047)	T-3648, Sub 1	9-9-93
Denton, Rodney A. (C-2032)	T-3731, Sub 1	6-18-93
Draughon, Roscus (P-479)	T-2501, Sub 1	10-14-93
Gilliam & Son Trucking, Terry Wintfred Gilliam, d/b/a (P-689)	T-3665, Sub 1	5-7-93
Gooden Moving, Clione S. Gooden, d/b/a (C-1962)	T-3621, Sub 2	5-25-93
Guignard, L. B., Inc. (P-457)	T-2407, Sub 2	3-9-93
Heritage Homes, Inc. (C-1172)	T-2150, Sub 4	11-24-93
J.E.D. Transport, Inc. (C-889)	T-2817, Sub 2	7-7-93
Lattimore Trucking, Barbara Lattimore, d/b/a (C-1679)	T-3703, Sub 2	1-21-93
Leon's Enterprise, Inc. (C-1987)	T-3660, Sub 1	1-19-93
Metropolitan Services, Inc. (C-1919)	T-3533, Sub 1	10-27-93
Mullen, Henry Trucking, Inc. (CP-137)	T-2478, Sub 6	12-10-93
Myers Men, Inc. (C-1600)	T-2954, Sub 2	10-27-93
Priority Freight Systems, Inc. (C-1879)	T-3453, Sub 1	2-5-93
Rush, Wilbur James (C-1857)	T-3402, Sub 2	1-13-92

S & S Trucking Company (C-1247)	T-2318, Sub 3	1-25-93
Star Express, Inc. (C-1445)	T-2724, Sub 2	4-19-93
Taylor's of Fayetteville, Inc. (P-691)	T-3724, Sub 1	12-14-93
Temperature Controlled Carriage, Inc. (C-1479)	T-3476, Sub 2	7-15-93
Twin City Warehouses, Inc. (P-444)	T-2348, Sub 3	10-6-93
Watson Transportation Company, H. Elwin Watson, d/b/a (P-103)	T-822, Sub 2	1-25-93
Yeary Transfer Company, Inc. (C-728)	T-1014, Sub 6	8-6-93

American Mobile Home Moving Service, William M. Giles, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1640 - Termination of Liability and Cargo Insurance Coverage
T-3002, Sub 3 (1-11-93)

B & I Trucking Company, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1885 - Termination of Liability Insurance Coverage
T-3305, Sub 1 (10-27-93)

Baucom's Transfer & Storage Company, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-714 - Termination of Cargo Insurance Coverage
T-959, Sub 3 (8-23-93)

Billy's Home Service, George W. Layton, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1414 - Termination of Liability and Cargo Insurance Coverage
T-2661, Sub 3 (7-19-93)

Ed's Mobile Home Movers, Grover E. Johnson, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1448 - Termination of Cargo Insurance Coverage
T-2714, Sub 1 (12-14-93)

G & S Towing, Walter Lee Starnes, Jr., d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-2041 - Termination of Liability and Cargo Insurance Coverage
T-3727, Sub 1 (7-19-93)

Hoss, Charles E. - Recommended Order Cancelling Operating Authority Certificate No. C-1967 - Termination of Liability and Cargo Insurance Coverage
T-3635, Sub 2 (3-16-93)

Humboldt Express, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1603 - Termination of Cargo Insurance Coverage
T-2828, Sub 1 (2-22-93)

Johnson Brothers Truckers, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1339 - Termination of Cargo Insurance Coverage
T-3480, Sub 1 (7-1-93)

ORDERS AND DECISIONS LISTED

Joyful Homes, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1005 - Termination of Liability and Cargo Insurance Coverage
T-1575, Sub 8 (10-13-93)

K & K Mobile Home Movers, Keith Arnold, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1931 - Termination of Cargo Insurance Coverage
T-3468, Sub 2 (5-19-93)

Leonard Edge Auto Sales, Leonard Edge, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1751 - Termination of Liability Insurance Coverage
T-3224, Sub 1 (4-26-93)

Pioneer Trucking Company - Recommended Order Cancelling Operating Authority Certificate No. C-1361 - Termination of Liability Insurance Coverage
T-2548, Sub 4 (1-11-93)

Shaw, A. L. & Sons Trucking Company, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1309 - Termination of Liability Insurance Coverage
T-2442, Sub 7 (2-1-93)

She Express, Sandi Trucking, Inc., d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1955 - Termination of Liability Insurance Coverage
T-3618, Sub 1 (5-19-93)

Sky Delivery Service, Timothy Hamilton, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-2006 - Termination of Cargo Insurance Coverage
T-3633, Sub 1 (12-14-93)

South Freight Service, Inc. - Recommended Order Cancelling Operating Authority Certificate/Permit No. CP-60 - Termination of Cargo Insurance Coverage
T-2219, Sub 2 (2-22-93)

TBT Corp. - Recommended Order Cancelling Operating Authority Certificate No. C-2046 - Termination of Liability Insurance Coverage
T-3749, Sub 1 (11-23-93)

Triangle Quality Transport, Inc. Recommended Order Cancelling Operating Authority Certificate No. C-1924 - Termination of Liability Insurance Coverage
T-3385, Sub 1 (9-7-93)

W & R Services, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1994 - Termination of Cargo Insurance Coverage
T-3700, Sub 1 (9-13-93)

ORDERS AND DECISIONS LISTED

RESCINDING AUTHORIZED SUSPENSION AND CANCELLED AUTHORITY

Company	Docket Number	Date
Billy's Home Service, George W. Layton, d/b/a	T-2661, Sub 3	8-11-93
Joyful Homes, Inc.	T-1575, Sub 8	11-15-93
Shaw, A. L. and Sons Trucking Company	T-2442, Sub 7	12-15-93
Sky Delivery, Timothy Hamilton, d/b/a	T-3633, Sub 1	12-16-93

COMPLAINTS

McCollister's Moving & Storage, Inc. - Order Giving Notice of Intent to Close Docket in Complaint of (See Official Copy of Order in Chief Clerk's Office for list of Companies)
T-3634, Sub 2 (11-2-93)

McCollister's Moving & Storage, Inc. - Order Closing Docket in Complaint of (See Official Copy of Order in Chief Clerk's Office for list of Companies)
T-3634, Sub 2 (12-3-93)

Wendell Transport Corporation - Order Holding Motions in Abeyance in Complaint of North Carolina Intrastate Petroleum Rate Committee of the North Carolina Trucking Association, Inc.
T-1039, Sub 19 (1-7-93)

Wendell Transport Corporation - Order Denying Motion for Reconsideration in Complaint of North Carolina Intrastate Petroleum Rate Committee of the North Carolina Trucking Association, Inc.
T-1039, Sub 19 (10-26-93)

MERGER

Dry Storage Corporation - Order Approving Merger with Carmac Transport, Inc., Holder of Certificate No. C-1673
T-3837 (7-19-93)

General Transport Systems, Inc. - Order Approving Merger with General Transport Systems, Inc., d/b/a General Transport Systems of Delaware, Inc., Holder of Certificate/Permit No. CP-108, with General Transport Systems, Inc., Being the Surviving Corporation
T-2875, Sub 4 (1-13-93)

Santee Carriers, TIC United Corp., d/b/a - Order Approving Merger with Santee Carriers, Inc., Certificate/Permit No. CP-63
T-1412, Sub 11 (12-20-93)

NAME CHANGE/TRADE NAME

Biggs, R. D. Transportation, Inc. - Order Approving Name Change from Robert D. Biggs, d/b/a R. D. Biggs Transportation, Permit No. P-668
T-3551, Sub 1 (6-2-93)

Blue Ridge Transfer, BRT Trucking, Inc., d/b/a - Order Approving Name Change from Lily Transportation Corp., d/b/a Blue Ridge Transfer, Certificate No. C-1093
T-1897, Sub 5 (8-24-93)

Brodie's Moving Service, Ltd. - Order Approving Name Change from Norris C. Brodie, d/b/a Brodie's Moving Service, Certificate C-2035
T-3784 (2-12-93)

Carolina-Friendship Express, Inc. - Order Approving Name Change from Michael E. Medley and James R. Allison, Jr., d/b/a Carolina Express, Certificate No. C-1766
T-3779 (2-5-93)

Crawford Deliveries, Bernard Crawford, d/b/a - Order Approving Name Change from Crawford Deliveries, Inc., Permit No. P-426
T-2290, Sub 3 (10-15-93)

Delicate Touch Delivery, Inc. - Order Approving Name Change from Steven R. Ennis, d/b/a Delicate Touch Delivery, Certificate No. C-1876
T-3451, Sub 1 (7-28-93)

Farmer, Bobby G. Trucking, Bobby G. Farmer, d/b/a - Order Approving Name Change from Bobby G. Farmer, Certificate No. C-2059
T-3790, Sub 1 (5-12-93)

Fox Mobile Home Movers, Elmer Leon Fox, d/b/a - Order Approving Name Change from Elmer Leon Fox, Certificate No. C-2079
T-3832, Sub 1 (8-16-93)

GATX Freight Systems, Inc. - Order Approving Name Change from Unit Transportation, Inc., Certificate no. C-1864
T-3841 (6-17-93)

Jones Trucking, John Paul Jones, d/b/a - Order Approving Name Change from John Paul Jones and John Taylor Woolard, d/b/a J & W Transport Co., Certificate No. C-1906
T-3830 (5-19-93)

Joy Vee Truck Service, Stephen Coble Perdue, d/b/a - Order Approving Name Change from Joyce Smith Perdue, d/b/a Joe Vee Truck Service, Certificate No. C-1981
T-3564, Sub 2 (8-6-93)

Patterson Transport, Inc. - Order Approving Name Change from Robert H. Patterson and Robert S. Patterson, d/b/a Patterson Trucking, Permit No. P-633
T-3330, Sub 1 (2-11-93)

Priority Transport Express, Inc. - Order Approving Name Change from Brookshire Express Services, Inc., Certificate/Permit No. CP-139
T-3927 (12-14-93)

Quality Transport of N.C., Inc. - Order Approving Name Change from Triangle Quality Transport, Inc., Certificate No. C-1924
T-3883 (9-16-93)

Raleigh Road Box Co. - Order Approving Name Change from Charlie Moses Smith, d/b/a Raleigh Road Box Co., Certificate No. C-2075
T-3609, Sub 1 (7-23-93)

Rocor Transportation Companies, Rocor International, d/b/a - Order Approving Name Change from Rocor Transportation Companies, Inc., Certificate No. C-1631
T-3341, Sub 2 (1-13-93)

Rogers & Rogers, Inc. - Order Approving Name Change from Randy Joe Rogers, d/b/a L & R Trucking, Certificate no. C-2015
T-3820 (4-28-93)

Ryder Dedicated Logistics, Inc. - Order Approving Name Change from Ryder Distribution Resources, Inc., Permit No. P-423. (2-11-93)

Shea Transport, George Wayne Christian and Myra Christian, d/b/a - Order Approving Name Change from Wayne Christian, d/b/a Shea Transport, Certificate No. C-2068
T-3794, Sub 1 (8-30-93)

Simmons, Dwight, Sr., Inc. - Order Approving Name Change from Dwight Simmons, Sr., Certificate No. C-2033
T-3670, Sub 1 (12-9-93)

Smith, Donald A. Co., Inc. - Order Approving Name Change from Donald A. Smith Certificate No. C-1317
T-2450, Sub 3 (1-28-93)

The Kannapolis & Concord Moving Co., Charles R. Fox, Sr., d/b/a - Order Approving Name Change from Charles R. Fox, Sr., d/b/a Wyatt & Son Moving & Storage, Certificate No. C-1703
T-3829 (6-11-93)

Turner Freight Systems, Inc. - Order Approving Name Change from Turner Trucking Company, Certificate No. C-2065 (10-11-93)

WestPoint Stevens, Inc. - Order Approving Name Change from Valley Fashions Corp., Certificate No. C-1947
T-3928 (12-10-93)

Young Express, Inc. - Order Approving Name Change from Young Moving & Storage, Inc., d/b/a Young Express, Certificate No. C-1960
T-3583, Sub 2 (1-5-93)

RATES - MOTOR COMMON CARRIERS

Central Transport, Inc. - Recommended Order Allowing Rate Increase Scheduled to Become Effective on August 1, 1993
T-740, Sub 16 (7-29-93) Order Adopting Recommended Order (7-30-93)

Morgan Drive Away, Inc. - Recommended Order Allowing Rate Increase on Shipments of Mobile Homes Scheduled to Become Effective February 4, 1993
T-1069, Sub 14 (3-24-93) Order Adopting Recommended Order (3-24-93)

Motor Common Carriers - Recommended Order Approving General Increase in Rates and Charges Applicable to Shipments of General Commodities
T-825, Sub 325 (3-22-93) Order Allowing Recommended Order to Become Effective and Final (3-22-93)

North Carolina Trucking Association, Inc. - Recommended Order Allowing Rate Increase in Various Rates and Charges Published in Petroleum Tariff N. 5-Y, NCUC 177, and Various Rates and Charges Published in Asphalt Tariff No. 16-M, NCUC 176, Scheduled to Become Effective on March 4, 1993
T-825, Sub 324 (3-26-93) Order Adopting Recommended Order (3-26-93)

SALES AND TRANSFER/CHANGE OF CONTROL

A A A Moving and Storage, Phillip P. Latham, d/b/a - Order Approving Sale and Transfer of Certificate No. C-677 from Mid-State Moving Company, Inc.
T-3856 (8-13-93)

A. C. Express of Raleigh, Inc. - Order Approving Sale and Transfer of a Portion of Certificate No. C-252 from Horne Storage Company, Inc.
T-3823 (6-16-93) Errata Order (6-18-93)

Bill's Courier Service, Luna's Trading Post, Inc., d/b/a - Order Approving Sale and Transfer of Certificate No. C-1971 from Robert L. and Patsy L. Racine, d/b/a Cardinal Courier Service
T-3891 (11-19-93)

Blue Ridge Transfer, Lily Transportation Corp., d/b/a - Order Granting Request to Transfer Certificate No. C-1093 from Blue Ridge Transfer Company, Inc.
T-1897, Sub 4 (6-25-93)

B.R.S. Enterprises, Inc. - Order Approving Sale and Transfer of Certificate No. C-1353 from Hildebran Freight, Inc.
T-3888 (11-19-93) Errata Order (11-30-93)

Bunch Transport, Inc. - Order Approving Sale and Transfer of Certificate No. C-1420 from F. C. Proctor, Inc.
T-3838 (7-19-93)

Cape Fear Transport, Inc. - Order Approving Sale and Transfer of Certificate No. C-942 from Hollowell Transportation Company
T-3384, Sub 2 (7-19-93)

Coastal Carrier, Richard S. Bunting, d/b/a - Order Approving Sale and Transfer of a Portion of Certificate No. C-170 from Everett Express, Inc.
T-3816 (5-17-93)

Corporate Moving Systems, Inc. - Order Approving Sale and Transfer of Certificate No. C-1132 from All American Moving & Storage, Inc.
T-3712, Sub 1 (1-13-93)

Crofutt & Smith Storage Warehouse of North Carolina, Inc. - Order Approving Sale and Transfer of a Portion of Certificate No. C-19 from Blue Ridge Trucking Company
T-3803 (4-15-93)

Ehmke/Carolina Movers, Inc. - Order Approving Sale and Transfer of Certificate No. C-976 from Carolina Moving and Storage, Inc.
T-3804 (4-15-93)

Goodman's Mobile Home Movers, Rick L. Goodman, d/b/a - Order Approving Sale and Transfer of Certificate No. C-967 from Charles C. Laughinghouse, d/b/a Charles C. Laughinghouse Mobile Home Movers
T-3839 (7-19-93)

Hallmart Distributors, Inc. - Order Approving Sale and Transfer of Certificate/Permit No. CP-103 from Richard M. Stearns, Trustee in Bankruptcy, F.M.B. Transport, Inc., d/b/a Glass Container Transport
T-3694, Sub 1 (1-22-93)

JT's Mobile Home Movers and Set Up, Tyner and Tyner Builders, Inc., d/b/a - Order Approving Sale and Transfer of Certificate No. C-1966 from Jesse Thurman Thompson, d/b/a J. T. Thompson Mobile Home Movers
T-3879 (10-15-93)

MAKO Transportation, Inc. - Order Approving Sale and Transfer of Certificate No. C-1730 from Melvin Thomas Mangum, d/ba M & J Trucking
T-3513, Sub 4 (5-18-93)

Markethouse Moving and Storage, Inc. - Order Approving Sale and Transfer of Certificate No. C-710 from Burk's Moving and Storage, Inc.
T-3857 (8-13-93)

Metrolina Movers, Metrolina Moving Systems, Inc., d/b/a - Order Approving Sale and Transfer of Certificate No. C-640 from Harold J. Proffitt, d/b/a Move-It Company
T-3835 (7-19-93)

Miller Mobile Home Moving, Raymond Kenneth Miller, d/b/a - Order Approving Sale and Transfer of Certificate No. C-1243 from Edwin Minton
T-3783 (3-19-93)

Montgomery Tank Lines, Inc. - Order Approving Transfer of Permit No. P-4676 from Quality Carriers, Inc.
T-3697, Sub 2 (11-19-93)

Norris Heavy Equipment Hauling, Norris Landscaping, Inc., d/b/a - Order Approving Sale and Transfer of Certificate No. C-1944 from Edwin I. Ennis, Jr., d/b/a Ennis Heavy Equipment Rentals & Sales
T-3901 (11-19-93)

Passmore Mobile Home Transit, Inc. - Order Approving Sale and Transfer of Certificate No. C-1585 from Johnny Jolly, d/b/a Mobile Home Movers and Service
T-3777 (3-19-93)

Paxton Van Lines, Paxton Van Lines of North Carolina, Inc. - Order Approving Sale and Transfer of Certificate No. C-372 from Piedmont Movers, Inc.
T-3814 (5-17-93)

SFI, Inc., Southern Freight, Inc., d/b/a - Order Approving Sale and Transfer of Certificate No. C-438 from Custom Transport, Inc.
T-3328, Sub 1 (3-19-93)

Smalley Transportation Company - Order Approving Sale and Transfer of Certificate No. C-356 from Standard Trucking Company
T-3887 (10-15-93)

Tobacco Transport of Kentucky, Tobacco Transport, Inc., d/b/a - Order Approving Sale and Transfer of a Portion of Certificate No. C-47 from Old State Motor Lines, Inc.
T-3834 (6-16-93) Errata Order (6-18-93)

Triangle Moving Service, Martin Amos, d/b/a - Order Approving Sale and Transfer of Certificate No. C-932 from Tommy Campbell, d/b/a Campbell's Transfer
T-3809 (5-17-93)

West's Durham Transfer & Storage, Inc. - Order Approving Transfer of Control of West's Durham Transfer & Storage, Inc., Holder of Certificate No. C-660, by Stock Transfer from Barney West and Manley J. West to John E. Clayton, Jr.
T-1865, Sub 4 (4-15-93)

Wyatt & Son Moving & Storage, Charles R. Fox, Sr., d/b/a - Order Approving Sale and Transfer of Certificate No. C-1703 from George Wyatt and Billy Ray Wyatt, d/b/a Wyatt & Son
T-3194, Sub 1 (3-18-93)

TARIFFS

American Messenger Services, Inc. - Recommended Order Approving Tariff Filings
T-3148, Sub 3 (9-27-93) Order Allowing Recommended Order to Be Effective (9-27-93)

DSI Transports, Inc. - Recommended Order Vacating Order of Investigation and Allowing Tariff Filing to Become Effective as Scheduled
T-3049, Sub 2 (9-9-93) Order Allowing Recommended Order to Be Effective September 10, 1993 (9-9-93)

Gooden Moving, Clione S. Gooden, d/b/a - Order Approving Tariff Rates and Charges NUNC PRO TUNC
T-3621, Sub 1 (2-16-93)

Matlack, Inc. - Recommended Order Approving Tariff Filings
T-2281, Sub 5 (8-30-93) Order Allowing Recommended Order to be Effective (8-30-93)

Wendell Transport Corporation - Order Allowing Cancellation of Tariff Implementing an Increase in Rates and Charges Scheduled to Become Effective May 15, 1993
T-1039, Sub 20 (6-4-93)

Wendell Transport Corporation - Recommended Order Approving Tariff Filing
T-1039, Sub 21 (7-15-93) Order Adopting Recommended Order Approving Tariff Filing (7-15-93)

MISCELLANEOUS

AAA Cooper Transportation - Order Granting Request to Self-Insure
T-2482, Sub 1 (3-17-93)

ABF Freight System, Inc. - Order Granting Request to Self-Insure
T-1583, Sub 3 (8-31-93)

Brytran, Inc. - Order Reinstating Certificate and Granting Authorized Suspension of Operations
T-2923, Sub 1 (1-20-93)

Chemical Leaman Tank Lines, Inc. - Order Granting Request to Self-Insure
T-663, Sub 30 (2-16-93)

Powell Trucking, Charles Mitchell Powell, d/b/a - Order Granting Motion to Transport Group 19 Unmanufactured Tobacco and Accessories
T-3584, Sub 1 (5-19-93)

Ryder Dedicated Logistics, Inc. - Order Granting Petition for Waiver of Rule R2-10(c)
T-3781, Sub 4 (4-27-93)

United Parcel Service, Inc. - Order Closing Docket
T-1317, Sub 30 (10-15-93)

RAILROADS

MOBILE AGENCY AND NONAGENCY STATIONS

CSX Transportation, Inc. - Order Granting Application to Establish Consolidated Agency Service Provided by Its Customer Service Center at Jacksonville, Florida in Lieu of its Existing Agency at Goldsboro
R-71, Sub 206 (3-2-93)

CSX Transportation, Inc. - Order Granting Application to Serve Solely with Its Customer Service Center the Customers Presently Being Served By the Customer Service Center in Jacksonville, Florida, and the Mobile Agent Based at Hamlet, North Carolina
R-71, Sub 208 (2-26-93)

CSX Transportation, Inc. - Order Granting Application to Serve Solely With Its Customer Service Center the Customers Presently being Served by the Customer Service Center and Mobile Agent Based at Raleigh, North Carolina
R-71, Sub 209 (8-2-93)

CSX Transportation, Inc. - Order Granting Application to Remove Various Inactive Stations from Agent McBride's Open and Prepay Station List
R-71, Sub 210 (8-9-93)

Chesapeake & Albemarle Railroad Company, Inc. - Order Granting Application for Certificate of Public Convenience and Necessity
R-75 (8-18-93)

Norfolk Southern Railway Company - Order Granting Application to Discontinue Agency Operations at Badin, and to Place Badin under the Jurisdiction of Mobile Agency Route NC-10 to be Relocated to Linwood
R-4, Sub 166 (8-11-93)

North Carolina & Virginia Railroad Company, Inc. - Order Granting Application for Certificate of Public Convenience and Necessity
R-76 (8-18-93)

TELEPHONE

APPLICATIONS AMENDED, CANCELLED, TERMINATED, WITHDRAWN OR DENIED

Access Enterprises - Order Dismissing Application to Offer Shared and/or Resold (STS) Telephone Service
STS-21 (10-6-93)

Amer-I-Net Services Corporation - Order Allowing Withdrawal of Application to Provide Long Distance Telecommunications Services Within the State of North Carolina
P-338 (7-2-93)

BSN Telecom Company; Phoenix Network, Inc. - Order Cancelling Certificate and Intrastate Tariffs and Denying Motion for Refunds
P-269, Sub 1; P-239, Sub 1 (5-12-93)

Cherry Communications - Order Allowing Withdrawal of Application and Closing Docket
P-329 (10-20-93)

Corporate Telemanagement Group, Inc. - Order Amending Certificate to Provide Intralata Long Distance Service
P-252 (5-26-93)

Enterprise Telecom Services, Inc. - Order Allowing Withdrawal and Closing Docket
P-310 (8-25-93)

EQuality, Inc. - Order Allowing Withdrawal of Application Without Prejudice
P-358 (11-29-93)

MA BELL Marketing, Ma Bell Associates, Inc., d/b/a - Order Allowing Withdrawal of Application without Prejudice
P-319 (6-1-93)

MCI Telecommunications Corporation - Order Denying Motions for Reconsideration
P-141, Sub 19; P-100, Sub 65; P-100, Sub 72 (1-5-93)

Ocracoke Telephone Company, Hal K. Snyder, d/b/a - Order Amending COCOT Certificate to Authorize Automated Collect Service
SC-878, Sub 1 (12-23-93)

On Tap Communications, Inc. - Order Dismissing Application to Offer Shared and/or Resold (STS) Telephone Service
STS-26 (10-6-93)

One Call Communications, Inc. - Order Amending Certificate to Include Intrastate IntraLATA Telecommunications Services
P-264, Sub 2 (12-14-93)

Sonic Communications, Inc. - Order Allowing Withdrawal of Application, Canceling Hearing and Closing Docket
P-330 (12-13-93)

The Equis Group - Order Dismissing Application to Offer Shared and/or Resold (STS) Telephone Service
STS-19 (10-6-93)

CERTIFICATES

AC America, Inc., Automated Communications, Inc., d/b/a - Recommended Order Granting Certificate to Provide Intrastate Interexchange Telecommunications Services on a Resell Basis
P-333 (4-29-93)

Alternate Communications Technology, Inc. Recommended Order Granting Certificate to Resale Interexchange Telecommunications Services
P-336 (12-9-93) Order Allowing Recommended Order to Become Effective (12-14-93)

Call Home America, Inc. - Recommended Order Granting Certificate to Provide Intrastate Interexchange Telecommunications Service
P-322 (4-12-93) Order Allowing Recommended Order to Become Final (4-15-93)

Communications Gateway Network, Inc. - Recommended Order Granting Certificate to Operate as a Reseller of Telecommunications Services within the State of North Carolina
P-317, Sub 1 (7-2-93)

Corporate Telemanagement Group, Inc. - Order Denying Motion for Reconsideration Except as to Uncollectibles for Certificate to Provide Intrastate Resale of Telecommunications Services (Commissioner Cobb did not participate in this decision. Commissioners Wright and Wells dissent.)
P-252 (3-10-93) Errata Order (3-16-93)

Eastern Telecom Corporation - Recommended Order Granting Certificate to Provide Intrastate Long Distance Telecommunications Service
P-318 (5-7-93)

Excel Telecommunications, Inc. - Recommended Order Granting Certificate to Resell Intrastate Interexchange Telecommunications Services within the State of North Carolina
P-270, Sub 1 (3-30-93) Order Allowing Recommended Order to Become Effective (4-5-93)

FEEK'S, Telecommunications, Inc. - Recommended Order Granting Certificate to Operate as a Reseller of Telecommunications Services within the State of North Carolina
P-334 (4-29-93)

GE Capital Communication Services Corporation, d/b/a GE EXCHANGE and d/b/a GE Capital EXCHANGE - Recommended Order Granting Certificate to Resell Intrastate Interexchange Telecommunications Services
P-348 (10-26-93) Order Allowing Recommended Order to Become Effective (11-2-93)

Hertz Technologies, Inc. - Recommended Order Granting Certificate to Provide and Resell Intrastate Interexchange Telecommunications Services as a Non-Facilities Based Switchless Reseller
P-335 (5-21-93) Order Allowing Recommended Order to Become Effective (5-24-93)

Lexington Telephone Long Distance Company - Recommended Order Granting Certificate to Provide InterLATA Long Oistance Services Within the State of North Carolina
P-323 (3-11-93)

One Call Communications, Inc. - Final Order Modifying Recommended Order to Provide Intrastate Telecommunications Services (Chairman Redman dissents and voted to affirm the Recommended Order.)
P-264 (1-29-93)

One Call Communications, Inc. - Recommended Order Granting Certificate to Provide Intrastate Interexchange Telecommunications Services on a Resell Basis
P-264, Sub 1 (9-24-93) Order Allowing Recommended Order to Become Effective (9-28-93)

Quest Telecommunications, Inc. - Recommended Order Granting Certificate to Provide Intrastate Long Distance Telecommunications Services
P-347 (11-10-93) Order Finalizing Recommended Order Granting Certificate (11-12-93)

Strategic Alliances, Inc. - Recommended Order Granting Certificate to Provide Interstate Interexchange Telecommunications Services
P-345 (11-12-93)

SUMMIT Telecommunications, Inc. - Recommended Order Granting Certificate to Provide Intrastate, Interexchange Telecommunications Services on a Resale Basis
P-349 (10-11-93) Order Allowing Recommended Order to Become Effective (10-20-93)

Target Telecom, Inc. - Recommended Order Granting Certificate to Operate as a Reseller of Telecommunications Services Within the State of North Carolina
P-325 (3-15-93) Errata Order & Addendum (4-13-93) Second Errata Order (4-14-93)

Telecommunications Services of America, TSA Consultants, Inc., d/b/a - Recommended Order Granting Certificate to Provide Intrastate Interexchange Telecommunications Services on a Resell Basis
P-311 (3-10-93)

TransNational Telephone - Recommended Order Granting Certificate to Provide Intrastate Telecommunications Service
P-344 (11-19-93) Errata Order (12-1-93)

U.S. Fibercom Network, Inc. - Recommended Order Granting Certificate to Provide Intrastate Interexchange Telecommunications Services within the State of North Carolina
P-320, Sub 1 (7-6-93)

WATS/800, Inc. - Order to Compel for a Certificate of Public Convenience and Necessity to Operate as a Reseller of Telecommunications Services Within the State of North Carolina
P-274, Sub 1 (1-12-93)

WATS/800, Inc. - Recommended Order Granting Certificate to Provide Intrastate Interexchange Resale Telecommunications Services
P-274, Sub 1 (7-13-93)

World Telecom Group, Inc. - Recommended Order Granting Certificate to Operate as a Reseller of Telecommunications Services Within the State of North Carolina
P-332 (4-29-93)

WorldTel Services, Inc. - Recommended Order Granting Certificate to Resell Intrastate Interexchange Telecommunications Services within the State of North Carolina
P-328 (3-1-93) Order Allowing Recommended Order to Become Effective (3-9-93)

COMPLAINTS

Central Telephone Company - Order Closing Docket in Complaint of Bettina Ruble
P-10, Sub 460 (5-26-93)

Concord Telephone Company - Order Dismissing Complaint and Closing Docket in Complaint of Harold A. Thornton, d/b/a Xeroxgraphic Copy Center & Quick Print Group
P-16, Sub 174 (5-26-93)

Concord Telephone Company - Order Reopening Docket in Complaint of Harold A. Thornton, d/b/a Xerographic Copy Center
P-16, Sub 174 (11-30-93)

IBA Telecom, Inc. - Order Keeping Docket Open for Six Months in Complaint of Cliff Hester
SC-622, Sub 1 (7-15-93)

MCI - Order Closing Docket in Complaint of Steve Edelman
P-141, Sub 24 (6-10-93)

North State Telephone Company - Order Keeping Docket Open for an Additional Six Months in Complaint of Peggy Bodenhamer
P-42, Sub 110 (5-26-93)

North State Telephone Company - Order Keeping Docket Open for an Additional Six Months in Complaint of Peggy Bodenhamer
P-42, Sub 110 (11-15-93)

North State Telephone Company - Order Keeping Docket Open for Six Months in Complaint of Mrs. Delia Miles
P-42, Sub 111 (1-7-93)

North State Telephone Company - Order Keeping Docket Open for an Additional Six Months in Complaint of Delia Miles
P-42, Sub 111 (7-8-93)

Southern Bell Telephone and Telegraph - Order Tentatively Finding no Good Cause to Investigate Complaint of Debbie Hart
P-55, Sub 975 (4-30-93)

Southern Bell Telephone and Telegraph Company - Order Dismissing Complaint and Closing Docket in Complaint of Debbie Hart
P-55, Sub 975 (6-10-93)

Southern Bell Telephone and Telegraph - Order Keeping Docket Open for Six Months in Complaint of Julie Rains, d/b/a Executive Correspondents
P-55, Sub 976 (1-7-93)

Southern Bell Telephone and Telegraph - Order Closing Docket in Complaint of Executive Correspondents, Julie Rains, d/b/a
P-55, Sub 976 (8-13-93)

Southern Bell Telephone and Telegraph - Drder Dismissing Complaint of S. Jackson White
P-55, Sub 983 (6-14-93)

Southern Bell Telephone and Telegraph - Order Denying Motion for Reconsideration and Affirming Order of June 14, 1993 in Complaint of S. Jackson White
P-55, Sub 983 (8-6-93)

Southern Bell Telephone and Telegraph Company - Order Granting Motion to Dismiss Appeal in Complaint of S. Jackson White
P-55, Sub 983 (11-1-93)

Southern Bell Telephone and Telegraph Company - Order Providing Notice and Opportunity to be Heard in Complaint of Robert D. Bryant, d/b/a Bryant Real Estate
P-55, Sub 985 (10-27-93)

Southern Bell Telephone and Telegraph Company - Order Dismissing Complaint of Robert T. Bryant, d/b/a Bryant Real Estate, and Closing Docket
P-55, Sub 985 (12-7-93)

Southern Bell Telephone and Telegraph Company and BellSouth Advertising and Publishing Company - Order Canceling Hearing and Closing Docket in Complaint of William Armentrout, d/b/a Armentrout's Carpet & Upholstery Cleaning
P-89, Sub 44 (1-13-93)

Southern Bell Telephone and Telegraph Company and BellSouth Advertising and Publishing Company - Order Closing Docket in Complaint of Raleigh Dermatology Associates, Dr. Fernando R. Puente, d/b/a
P-89, Sub 45 (9-16-93)

Sprint Communications Company LP - Order Closing Docket in Complaint of Steve Winter
P-294, Sub 1 (5-14-93)

EXTENDED AREA SERVICE (EAS)

Carolina Telephone and Telegraph Company - Order Authorizing No-Protest Notice, Columbus County-Seat, Extended Area Service
P-7, Sub 765 (2-24-93)

Carolina Telephone and Telegraph Company - Order Authorizing Extended Area Service - Columbus County-Seat Extended Area Service
P-7, Sub 765 (4-20-93)

Carolina Telephone and Telegraph Company - Order Authorizing Polling of Olivia to Fayetteville and Olivia to Lillington Extended Area Service (Commissioners Hughes, Cobb, and Duncan dissent.)
P-7, Sub 781 (9-28-93)

Carolina Telephone and Telegraph Company - Order Authorizing Polling for Selected Exchanges - Sampson County Extended Area Service
P-7, Sub 785 (5-6-93)

Carolina Telephone and Telegraph Company - Order Authorizing Poll - Red Springs to Fayetteville and Raeford Extended Area Service (Commissioner Tate dissents.)
P-7, Sub 789 (5-26-93)

Carolina Telephone and Telegraph Company - Order Authorizing Extended Area Service - Red Springs to Fayetteville and Raeford Extended Area Service
P-7, Sub 789 (8-18-93)

Carolina Telephone and Telegraph Company - Order Authorizing Polling - Oxford to Henderson Extended Area Service
P-7, Sub 792 (8-3-93)

Carolina Telephone and Telegraph Company - Order Approving Extended Area Service - Oxford to Henderson Area Service
P-7, Sub 792 (11-23-93)

Carolina Telephone and Telegraph Company - Order Authorizing Polling - Benson to Raleigh Extended Area Service (Commissioner Cobb voted "no".)
P-7, Sub 794 (9-8-93)

Carolina Telephone and Telegraph Company - Order Authorizing Extended Area Service - Benson to Raleigh Extended Area Service
P-7, Sub 794 (12-8-93)

Carolina Telephone and Telegraph Company - Order Authorizing Polling - Four Oaks to Raleigh Extended Area Service
P-7,1 Sub 795 (11-24-93)

Central Telephone Company - Order Authorizing Polling - State Road to Dobson and North Wilkesboro Extended Area Service
P-10, Sub 466 (8-25-93)

Ellerbe Telephone Company - Order Authorizing Cost Study - Ellerbe to Hamlet Extended Area Service
P-21, Sub 56 (6-22-93)

Ellerbe Telephone Company - Order Allowing Polling - Ellerbe to Hamlet EAS Proposal
P-21, Sub 56 (12-16-93)

GTE South - Order Authorizing No-Protest Notice - Liberty (Cherokee County) to Murphy and Suit Extended Area Service
P-19, Sub 253 (6-22-93)

GTE South - Order Approving Extended Area Service - Liberty (Cherokee County) to Murphy and Suit Extended Area Service
P-19, Sub 253 (8-11-93)

GTE South - Order Authorizing Cost Study - Cherokee to Sylva Extended Area Service
P-19, Sub 256 (6-3-93)

GTE South - Order Authorizing Polling - Cherokee to Sylva Extended Area Service
P-19, Sub 256 (12-16-93)

Lexington Telephone Company - Order Requiring Information on Denton and Thomasville to Lexington Extended Area Service
P-31, Sub 125 (1-12-93)

Lexington Telephone Company - Order Excusing North State Telephone Company from Hearing and Approving Rate Additives
P-31, Sub 125 (4-15-93)

Southern Bell Telephone and Telegraph Company - Order Authorizing Polling - Kimesville to Greensboro and Julian Extended Area Service
P-55, Sub 984 (7-13-93)

Southern Bell Telephone and Telegraph Company - Order Approving EAS Between Kimesville and Greensboro
P-55, Sub 984 (12-5-93)

Southern Bell Telephone and Telegraph Company - Order Authorizing Polling - Smithfield and Selma to Raleigh Extended Area Service
P-55, Sub 986 (10-12-93)

Southern Bell Telephone and Telegraph Company - Order Authorizing Poll - Taylorsville to Hickory Extended Area Service
P-55, Sub 987 (10-20-93)

Southern Bell Telephone and Telegraph Company - Order Authorizing Poll - Lenoir to Hickory Extended Area Service
P-55, Sub 989 (12-16-93)

MERGER

LDDS Communications, Inc. - Order Approving Merger with Metromedia Communications Corporation and Resurgens Communications Group, Inc.
P-283, Sub 5 (8-9-93)

Metromedia Communications Corporation and Resurgens Communications Group, Inc. - Order Approving Merger and Name Change to Metromedia Communications Corporation
P-246, Sub 4 (4-22-93)

Sprint Corporation and Centel Corporation - Order Approving Merger of Sprint Corporation and Centel Corporation
P-10, Sub 455 (1-15-93)

Teledial America of North Carolina, Inc. - Order Granting Authorization to Merge and Change Control of the Corporation with Teledial America, Inc.
P-266, Sub 4 (8-5-93)

Teledial America of North Carolina, Inc. and Teledial America, Inc. - Order Canceling Authority to Merge
P-266, Sub 4 (10-12-93)

RATES

AT&T Communications of The Southern States, Inc. - Order Modifying Capped Rate Plan as Applied to AT&T
P-140, Sub 36; P-100, Sub 72 (6-14-93)

MCI Telecommunications Corporation - Order Allowing Billing to InterLATA Access Charges for IntraLATA 10XXX-0 Traffic Subject to Application of Surcharge
P-141, Sub 19; P-100, Sub 65; P-100, Sub 72 (5-5-93)

SALES AND TRANSFER

TELNET Communications, Inc. - Order Approving Transfer of Customers of North Subscribers to Mid-Com Communications, Inc., and Discontinuance of Intrastate Service
P-242, Sub 3; P-308, Sub 1 (6-29-93)

The Concord Telephone Company - Order Approving Plan of Reorganization and Share Exchange and for Transfer of Control
P-16, Sub 175; P-295, Sub 3 (9-28-93)

SECURITIES

Carolina Telephone and Telegraph Company - Order Granting Authority to Issue and Sell up to $175,000,000 Principal Amount Debentures, with Maturities not to Exceed Thirty (30) Years
P-7, Sub 790 (7-16-93)

Corporate Telemanagement Group, Inc. - Order Approving Sale of Assets of The Hogan Company
P-252, Sub 5 (8-23-93)

Dial Page, Inc. - Order Granting Authority to Issue and Sell up to $90,000,000 Principal Amount Senior Notes
P-172, Sub 16 (2-10-93)

Dial Page, Inc. - Order Approving Dial Page, Inc., Equity Incentive Plan and Authorizing Issuance of Up to 1,250,000 Shares of Common Stock
P-172, Sub 17 (4-26-93)

FEEK'S Telecommunications, Inc., and Mid-Com Communications, Inc. - Order Approving Sale of Assets
P-334, Sub 1; P-308, Sub 3 (11-10-93)

GTTE Corporation - Order Approving Contract Relating to Inter-Company Loans and Interest
P-19, Sub 252 (3-19-93)

LDDS Communications, Inc., and LDDS of Carolina, Inc. - Order Granting Authority to Acquire the Assets of Tri-Tel
P-283, Sub 4 (2-19-93)

Mebane Home Telephone Company - Order Approving Loan from the Rural Telephone Bank
P-35, Sub 88 (5-14-93)

Service Telephone Company - Order Approving Loan from the Rural Electrification Administration
P-60, Sub 54 (11-16-93)

SPECIAL CERTIFICATES

Docket Number	Date	Company
SC-396, Sub 1	12-3-93	International Payphones of North Carolina
SC-799, Sub 1	6-16-93	Simplex Payphones, William D. Rubel, d/b/a
SC-807	1-13-93	Robert W. McCory
SC-808	1-13-93	Kirby James Cooper
SC-809	2-12-93	Gene Blanton
SC-810	2-12-93	Eugene K. Wannenburg
SC-811	2-24-93	Villa Sorrento, Inc.
SC-812	2-24-93	Steve Douglas Goode
SC-813	3-4-93	Douglas M. Taylor
SC-814	3-4-93	WIC-Orange Inc.
SC-815	3-4-93	Paycom, Baxter B. Sapp III, d/b/a
SC-816	3-4-93	Gerald R. Smith
SC-817	3-4-93	Richard William Ward
SC-818	3-17-93	Robert T. Taylor, d/b/a G T Vends
SC-819	3-17-93	Accelerated Communications Corporation
SC-820	3-17-93	Inter-Texas Leasing, Inc.
SC-821	4-2-93	Baker Communications, Inc.
SC-822	4-2-93	Philip Christy, d/b/a CCT Christy's Coin-op Telephones
SC-823	4-2-93	Technicall, Baxter B. Sapp, III, d/b/a
SC-824	4-20-93	Paul E. Dishman
SC-825	4-20-93	Howell A. Robinson, Jr.
SC-826	4-20-93	Dennis Gene Eshbaugh
SC-827	5-6-93	Michael T. Varner, d/b/a Watauga Telephone Company
SC-828	5-6-93	Kathryn T. Jeidy, Telefax Opportunities
SC-829	5-6-93	Toby L. Faw
SC-830	5-12-93	Edward C. Martin
SC-831	5-12-93	Koon Hai Wang
SC-832	5-20-93	Southeastern Telephone Company, Inc.
SC-833	5-20-93	Dairy Fresh, Inc.
SC-834	5-20-93	Z-Tech Inc.
SC-835	6-1-93	Lynn P. Lewis
SC-836	6-1-93	James Michael Smith
SC-837	6-3-93	Payphone Services, Inc.

SC-838	6-16-93	Joe Carney
SC-839	6-21-93	Talton Carolina, Inc.
SC-840	7-12-93	Peter A. Pentony
SC-841	7-12-93	Hospitality Payphone Service, Ronald C. Summerlin, d/b/a
SC-842	7-15-93	Pinehurst FS. Incorporated
SC-843	7-15-93	Carolina Orange Phone, Ronald B. Hunter, d/b/a
SC-844	7-15-93	Hospitality Telecom, Inc., Hospitality Communications, Inc., d/b/a
SC-845	7-15-93	Hoffer Flow Controls, Inc.
SC-846	8-3-93	National Security Associates, Joseph F. Balzano
SC-848	8-25-93	Ougan Enterprises, Inc., d/b/a Cointel Carolina
SC-849	8-27-93	Lange Enterprises, Dale L. Lange, d/b/a
SC-850	8-27-93	Greensboro Golf Center
SC-851	9-9-93	Neuse Baptist Church
SC-852	8-27-93	Roy W. Gossett
SC-853	9-16-93	Happy Holiday Campground, Happy Holiday Enterprises, Inc., d/b/a
SC-854	8-27-93	North Henderson High School
SC-855	8-27-93	Coin Communications, William Henry Royster, d/b/a
SC-856	9-13-93	Joseph Adu
SC-857	9-9-93	Christine Baxter
SC-858	9-10-93	Advantage Mail Network, Shoppers Advantage, Inc., d/b/a
SC-859	9-9-93	Mearers Phone Service, William F. Mearers, d/b/a
SC-860	9-13-93	Adams Computer Sales
SC-861	10-19-93	Roy Joseph Clifton
SC-862	9-28-93	Lucas Cirtek Corporation
SC-863	10-4-93	Stan C. Lee
SC-864	10-4-93	R J V Enterprises, Inc.
SC-866	10-19-93	Steven R. Campbell
SC-867	10-12-93	Christine Baxter, d/b/a Laurel Hill Telcom
SC-868	10-20-93	Ram L. Farmah
SC-869	10-19-93	Robert Dennis Lewis, d/b/a Sportspage Restaurant
SC-870	10-19-93	Earl E. Thompson
SC-871	10-19-93	Equity Pay Telephone Company, Inc.
SC-872	10-19-93	Goran Dragoslavic
SC-873	12-1-93	Hal K. Snyder, d/b/a Ocracoke Telephone Company
SC-874	11-9-93	Theodore Hammerman
SC-875	11-9-93	Donald W. Parnell
SC-877	11-19-93	David Band
SC-878	11-19-93	David Singleton
SC-879	11-19-93	Anthony Acevedo

SC-880	11-19-93	Anita M. Blanchard, d/b/a Coin-Tel
SC-881	11-19-93	Sam's Mart, Inc.
SC-883	12-1-93	R. L. Baillif
SC-884	12-1-93	Mebcom Communications, Inc., d/b/a Mebtel Systems
SC-885	11-30-93	Central Carolina Communications, Inc.
SC-886	12-23-93	James W. Wood
SC-887	12-23-93	Mandy Singleton
SC-888	12-23-93	John B. Joplin
SC-889	12-23-93	Joseph A. Santoro
SC-890	12-23-93	Michael J. Brooks
STS-23	7-7-93	North Carolina State University Telecommunications Office
STS-27	9-2-93	UNC-North Carolina School of the Arts
STS-28	8-3-93	The University of North Carolina at Charlotte
STS-29	8-19-93	Fayetteville State University
STS-30	8-12-93	North Carolina A & T State University

SPECIAL CERTIFICATES AMENDED, REVOKED, CANCELLED OR CLOSED

Docket No.	Date	Company
SC-3, Sub 5	10-4-93	Coin Telephones, Inc.
SC-14, Sub 1	9-28-93	Billie Veasey
SC-49, Sub 1	3-25-93	Stoney Hollow Condominium Regime
SC-185, Sub 1	8-9-93	Truck and Buss Center of High Point, Inc., Ed Sartin
SC-219, Sub 1	11-9-93	Turner Oil Company of Wilson, Inc.
SC-226, Sub 1	11-9-93	David Chin
SC-233, Sub 1	6-22-93	E. James Parker, Jr.
SC-255, Sub 1	3-10-93	Aurora Mini Mart
SC-278, Sub 1	7-22-93	William Verlin Murray
SC-279, Sub 1	11-19-93	Ingles Markets, Inc.
SC-281, Sub 1	8-16-93	Lytle Oil Company
SC-349, Sub 1	10-20-93	Thomas Roy Whitaker, d/b/a Roy's Grocery
SC-352, Sub 1	7-15-93	Roger Villarreal
SC-356, Sub 1	10-27-93	Sam's Car Washes
SC-390, Sub 1	11-1-93	Rhoden Enterprises, Inc.
SC-422, Sub 1	11-19-93	SKED Inc., d/b/a Arden Dairy Queen
SC-428, Sub 1	10-20-93	Key Largo Stores
SC-432, Sub 1	2-9-93	Wadeco Services, Inc.
SC-476, Sub 1	11-9-93	Olde Brunswick General Store
SC-478, Sub 1	10-12-93	Wesley's Grocery
SC-479, Sub 1	1-13-93	Patio Playground
SC-481, Sub 1	11-30-93	New Hanover High School
SC-497, Sub 2	1-19-93	I.C.C.A.
SC-525, Sub 3	12-13-93	MaxTel
SC-567, Sub 1	5-20-93	Walter J. Minton
SC-581, Sub 1	3-4-93	George A. Sekyi
SC-647, Sub 1	12-20-93	Asheville Mall, Inc.
SC-649, Sub 1	4-23-93	James C. Bibey
SC-658, Sub 1	10-20-93	Sushil Kashyap

SC-662, Sub 1	3-3-93	J. Edward Evans and Linda L. Evans
SC-689, Sub 1	7-16-93	Southeast High School/Halifax County
SC-693, Sub 1	6-29-93	Jerry C. Sparks
SC-709, Sub 2	9-3-93	Donald E. Axberg
SC-721, Sub 1	5-20-93	Tom's Food and Fuel, Boyce L. O'Tuel, Jr., d/b/a
SC-724, Sub 1	5-27-93	Supercade Amusements, Inc.
SC-725, Sub 1	3-12-93	James F. Rees, Jr.
SC-728, Sub 1	6-7-93	Davie High School
SC-733, Sub 1	5-6-93	Luby E. Wood
SC-736, Sub 1	9-28-93	Cirtek of North Carolina, Inc.
SC-738, Sub 1	1-11-93	Tommy D. Patterson
SC-762, Sub 1	1-20-93	J. R. Pierce
SC-765, Sub 1	6-7-93	Scott Goforth
SC-767, Sub 1	11-9-93	Paul Fisher
SC-772, Sub 1	12-30-93	Quarter Phones of North Carolina, Inc.
SC-773, Sub 1	7-21-93	GTA Enterprises, Inc.
SC-776, Sub 1	1-21-93	Chester Maritz
SC-785, Sub 1	4-16-93	Auditory Management Corporation
SC-790, Sub 1	4-20-93	McGuires Pub, Ltd.
SC-791, Sub 1	7-15-93	John A. Swaby, Jr.
SC-794, Sub 1	11-19-93	John Thomas Smithwick
SC-796, Sub 1	3-4-93	Edward P. Rawls
SC-797, Sub 1	2-5-93	Pat O. Sanchez
SC-798, Sub 1	8-3-93	Southern Metals Company, Inc.
SC-801, Sub 1	12-30-93	Dorothy Pigott
SC-817, Sub 1	11-1-93	Richard William Ward
SC-824, Sub 1	7-20-93	Paul E. Dishman
SC-851, Sub 1	11-16-93	Neuse Baptist Church
SC-868, Sub 1	12-3-93	Ram L. Farmah
SC-884, Sub 1	12-30-93	Mebcom Communications, Inc., d/b/a Mebtel Systems

SPECIAL CERTIFICATES REISSUING OR REINSTATED

Docket No.	Date	Company
SC-485, Sub 1	3-10-93	PhoneTel Technologies, Inc.
SC-847	8-19-93	Southeastern Telecom

TARIFFS

AT&T Communications of the Southern States, Inc. - Order Delaying Compliance Date to Eliminate the Day Save Rate Period for Its Message Telecommunications Service
P-140, Sub 34 (1-26-93)

AT&T Communications of the Southern States, Inc. - Order Allowing Original Filing to go into Effect to Offer Special Service Arrangement to Collins & Aikman Corporation
P-140, Sub 37 (11-30-93)

Barnardsville, Saluda Mountain, and Service Telephone Companies - Order Allowing Tariffs to go into Effect to Establish a Local Service Guarantee
P-75, Sub 43; P-76, Sub 35; P-60, Sub 55 (11-10-93)

Business Telecom, Inc. - Order Requiring Refund from those Contained in Approved Tariff (Commissioner Wells did not participate in this decision.)
P-165, Sub 14 (2-1-93)

GTE South - Order Suspending Tariff Filing to Add Call Announcement Capability to Its Automatic Call Return and Call Block Service Offerings

GTE South - Order Allowing Tariff Filing After Customer Notification by Bill Message (Commissioner Laurence A. Cobb dissents.)
P-19, Sub 255 (5-6-93)

GTE South and Contel of North Carolina, Inc., and Contel of Virginia, Inc. - Order Allowing Tariffs to Become Effective
P-19, Sub 257 (5-26-93)

North State Telephone Company - Order Allowing Tariffs to Establish Rates for the Calling Name Display Feature for Centrex Business Set Lines
P-42, Sub 113 (10-26-93)

MISCELLANEOUS

ALLTEL Carolina, Inc., and ALLTEL Cellular Associates of the Carolinas - Order on Negotiated Service Agreement
P-118, Sub 66 (2-24-93)

ALLTEL Carolina, Inc., and ALLTEL Mobile Communications of the Carolinas - Order on Negotiated Service Agreement
P-118, Sub 70 (11-4-93)

BellSouth Telecommunications, Inc. - Order Accepting Amendments to Affiliated Contracts for Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153
P-55, Sub 964 (8-3-93)

BellSouth Telecommunications, Inc. - Order Accepting Amendments to Affiliated Contracts for Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153
P-55, Sub 964 (12-22-93)

BellSouth Telecommunications, Inc., and Sunrise Trust - Order on Negotiated Agreement
P-55, Sub 981 (2-24-93)

BellSouth Telecommunications, Inc., and Centel Cellular Company of North Carolina Limited Partnership, and Raleigh-Durham MSA Limited Partnership - Order on Negotiated Service Agreements
P-55, Sub 982 (2-24-93)

Call Home America, Inc. - Order Requiring Accounting
P-322 (3-30-93)

Call Home America, Inc.,- Recommended Order Approving Payment of Penalty in Lieu of Refund and Approving Transfer of Customers and Discontinuance of Intrastate Service
P-322, Sub 1 (10-5-93) Order Finalizing Recommended Order (10-20-93)

Carolina Telephone and Telegraph Company and Sprint Publishing & Advertising Order Accepting Agreement for Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153
P-7, Sub 779 (4-21-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, sub 786 (6-15-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, Sub 786 (12-22-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, Sub 787 (6-15-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, Sub 787 (9-1-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreement
P-7, Sub 787 (12-22-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, Sub 787 (10-5-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, Sub 788 (6-15-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, Sub 788 (9-1-93)

Carolina Telephone and Telegraph Company - Order on Negotiated Service Agreements
P-7, Sub 788 (10-5-93)

Central Telephone Company of North Carolina - Order Accepting Affiliated Contract for Filing and Permitting Operation thereunder Pursuant to G.S. 62-153
P-10, Sub 457 (6-3-93)

Central Telephone Company - Order Closing Docket
P-10, Sub 458 (7-8-93)

Central Telephone Company of North Carolina - Order Accepting Affiliated Contract for Filing and Permitting Operation thereunder Pursuant to G.S. 62-153
P-10, Sub 459 (6-3-93)

Central Telephone Company of North Carolina - Order Granting Request to Withdraw Affiliated Contract
P-10, Sub 461 (6-3-93)

Central Telephone Company and ALLTEL Mobile Communications, Inc. - Order on Negotiated Service Agreement
P-10, Sub 462 (2-24-93)

Central Telephone Company and United States Cellular Operating Company of North Carolina RSA #7, Inc. - Order on Negotiated Service Agreement
P-10,1 Sub 463 (2-24-93)

Concord Telephone Company and Metro Mobile CTS of Charlotte, Inc. - Order on Negotiated Service Agreement
P-16, Sub 173 (2-24-93)

Concord Telephone Long Distance Company - Order Accepting Affiliated Contracts for Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153
P-295; P-295, Sub 1 (5-5-93)

Concord Telephone Long Distance Company - Order Accepting Affiliated Contracts for Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153
P-295 (8-3-93)

Contel of North Carolina, Inc. - Order on Negotiated Service Agreements
P-128, Sub 35 (12-22-93)

Crescent View - Order Closing Docket
STS-9 (4-12-93)

Oial Page, Inc. - Order Granting Dial Page Exemption From Commission's Prior Approval and other Requirements Under North Carolina General Statutes Chapter 62, Article 8 - Securities Regulation

FEEK's Telecommunications, Inc. - Recommended Order Fixing Penalty
P-334 (5-26-93)

GTE South - Order on Negotiated Service Agreements
P-19, Sub 260 (12-22-93)

Ma Bell Associates, Inc., d/b/a MA BELL Marketing - Order Approving Refund Proposal
P-319 (4-29-93)

Metromedia Communications Corporation - Order Closing Docket
P-246, Sub 3 (4-23-93)

Southern Bell Telephone and Telegraph Company - Order Allowing Oiscontinuance of Monthly Settlement Ratio Report
P-55, Sub 742; P-100, Sub 34 (3-12-93)

Sprint Communications Company LP - Order Requiring Penalty
P-294, Sub 2 (3-9-93) Errata Order (3-10-93)

WATS/800, Inc. - Order Approving Stipulation
P-274, Sub 1 (7-8-93)

World Telecom Group, Inc. - Recommended Order Fixing Penalty
P-332 (5-26-93)

WATER AND SEWER

APPLICATIONS AMENDED

Heater Utilities, Inc. - Order Amending Certificate to Furnish Water and Sewer Utility Service in Hawthorne Subdivision, Wake County
W-274, Sub 60 (3-23-93)

Holiday Island Property Owners Association - Order Amending Order of December 8, 1992
W-386, Sub 8 (1-19-93)

North State Utilities, Inc. - Order Amending Certificate to Furnish Sewer Utility Service in Saddleridge Subdivision, Wake County
W-848, Sub 14 (3-26-93)

APPLICATIONS WITHDRAWN, DENIED, OR DISMISSED

Blue Creek Utilities, Inc. - Order Allowing Withdrawal of Application, Cancelling Hearing, Requiring Public Notice, and Closing Docket
W-857, Sub 3 (3-30-93)

Bright Leaf Landing Corporation - Order Allowing Withdrawal Request and Closing Docket
W-994, Sub 1 (11-12-93)

Cape Fear Utilities, Inc., and Quality Water Supplies, Inc. - Order Allowing Withdrawal of Application, Cancelling Hearing, Requiring Public Notice, and Closing Dockets
W-279, Sub 25; W-225, Sub 21 (3-25-93)

Carolina Blythe Utility Company - Order Withdrawing Application and Closing Docket to Provide Water and Sewer Utility Service in Certain Service Areas, Brunswick County
W-503, Sub 4 (8-17-93)

Carolina Water Service, Inc. of North Carolina - Order Allowing Motion to Withdraw and Closing Docket No. W-354, Sub 127
W-354, Sub 118; W-354, Sub 127 (11-9-93)

Carolina Water Service, Inc. of North Carolina - Order Denying Motion to Strike Parts of Testimony
W-354, Sub 118 (11-10-93)

Carolina Water Service, Inc. of North Carolina - Order Denying Petition to Reduce Rates and Petition for Interim Order to Reduce Rates (Commissioner Tate dissents.)
W-354, Sub 126 (7-16-93)

Crosby Utilities, Inc. - Order Allowing Withdrawal of Application and Closing Docket
W-992, Sub 1 (12-1-93)

Forsyth Water Company, Inc. - Order Denying Request for Temporary Authority to Furnish Water Utility Service in Bishops Ridge Subdivision, Surry County, and Interim Rates
W-1027 (2-26-93)

Jones, J. W. - Order Allowing Withdrawal of Application, Canceling Hearing, Requiring Public Notice, and Closing Docket
W-422, Sub 3 (6-22-93)

McGowan Acres - Order Withdrawing Application to Furnish Sewer Utility Service in McGowan Acres Subdivision, Beaufort County, and Closing Docket
W-1010 (4-28-93)

Mid South Water Systems, Inc. - Order Dismissing Application to Provide Water and Sewer Utility Service in Bradfield Farms Subdivision, Phases III, IV and V, Mecklenburg and Cabarrus Counties, and Closing Docket
W-720, Sub 120 (2-10-93)

Mid South Water Systems, Inc. - Order Dismissing Application to Provide Water and Sewer Utility Service in Silverton Subdivision, Cabarrus County, and Closing Docket
W-720, Sub 121 (2-10-93)

Piedmont Construction and Water Company, Inc. - Order Denying Request for Approval to Use the Present Value Method
W-262, Sub 46 (10-22-93)

Prior Construction Company, Inc. - Order Allowing Withdrawal of Rate Increase Application and Setting Issues for Hearing
W-567, Sub 4 (3-23-93)

R.O.E. Water Company, Inc. - Order Allowing Withdrawal of Application and Closing Docket
W-820, Sub 11 (4-8-93)

Salt Works Point Utility, Inc. - Order Allowing Withdrawal of Application and Closing Docket
W-983 (12-29-93)

Sunset Park Utilities, Inc. - Order Withdrawing Application and Closing Docket
W-178, Sub 3 (10-28-93)

<u>CANCELLED OR REVOKED</u>

Colony Water Company of Morehead City, Inc. - Order Cancelling Franchise for Water Utility Service in Club Colony Subdivision, Carteret County
W-654, Sub 1 (8-4-93)

Junior Setzer, c/o, Public Utility Franchise of Quail Hollow Water System; Public Utility Franchise of Rollingwood Water System; Public Utility Franchise of Lake Terrace Water System - Order Cancelling Franchise Providing Water Utility Service in Quail Hollow Subdivision, Rollingwood Subdivision, and Lake Terrace Subdivision all in Cleveland County, and Closing Dockets
W-427, Sub 1; W-428, Sub 2; W-683, Sub 1 (3-11-93)

Kitty Hawk Utilities, Inc. - Order Canceling Franchise to Discontinue Service Utility Service in Its Franchised Area, Dare County
W-859, Sub 1 (4-15-93)

CERTIFICATES

Brookwood Water Corporation - Order Granting Franchise to Furnish Water Utility Service in Lake William Subdivision (Section I) and Lake Williams Subdivision (Section I), Cumberland County, and Approving Rates
W-177, Sub 35 (1-13-93)

Carolina Blythe Utility Company - Order Granting Franchise to Furnish Sewer Utility Service in Brunswick Plantation Subdivision, Brunswick County, and Approving Rates
W-503, Sub 5 (6-30-93)

Carolina Water Service, Inc. of North Carolina - Order Granting Certificate to Provide Sewer Utility Service in Farmwood 20 and 21, Habersham, and Windsor Chase Subdivisions, Mecklenburg County
W-354, Sub 121 (10-11-93)

Heater Utilities, Inc. - Order Granting Franchise to Furnish Water Utility Service in Southwyck and South Mountain Subdivision, Wake County, and Approving Rates
W-274, Sub 74 (2-2-93)

Heater Utilities, Inc. - Order Granting Franchise to Furnish Water Utility Service in Heatherstone West Subdivision, Wake County, and Approving Rates
W-274, Sub 76 (2-24-93) Errata Order (3-1-93)

Heater Utilities, Inc. - Order Granting Franchise to Furnish Water Utility Service in Oak Chase Subdivision, Wake County, and Approving Rates
W-274, Sub 78 (9-21-93)

Heater Utilities, Inc. - Order Granting Franchise to Furnish Water Utility Service in Wakefield Subdivision (Phase I), Wake County, and Approving Rates
W-274, Sub 80 (12-22-93)

Hydraulics, Ltd. - Order Granting Water Utility Franchise to Furnish Water Utility Service in Walker Heights Subdivision, Gaston County, Approving Rates, Canceling Hearing, and Closing Docket
W-218, Sub 87; W-1028 (4-14-93)

Hydraulics, Ltd. - Order Granting Water Utility Service in Knoll View Subdivision, Rowan County, and Approving Rates
W-218, Sub 90 (8-19-93)

Hydraulics, Ltd. - Order Granting Franchise to Furnish Water Utility Service in Kendale Wood Estates Subdivision, Guilford County
W-218, Sub 91 (12-8-93)

Mid South Water Systems, Inc. - Order Settling Record on Appeal to Provide Water and Sewer Utility Service in Bradfield Farms and Britley Subdivisions, Cabarrus and Mecklenburg Counties
W-720, Subs 96 and 108 (1-28-93)

Piedmont Construction and Water Company, Inc. - Order Granting Franchise to Furnish Water Utility Service in Sedgefield Subdivision, Catawba County, and Approving Rates
W-262, Sub 45 (9-14-93)

Turnpike Properties, Inc. - Recommended Order Granting Franchise to Furnish Water and Sewer Utility Service in Pine Island Subdivision, Currituck County, and Approving Rates
W-999 (3-18-93)

Watercrest Estates - Recommended Order Granting Water and Sewer Utility Franchise to Furnish Water and Sewer Utility Service in Watercrest Estates Mobile Home Park, Iredell County, and Approving Rates
W-1021 (3-16-93)

Wellington Mobile Home Park, Inc. - Interim Order Granting Franchise to Furnish Water and Sewer Utility Service in Wellington Mobile Home Park Subdivision, Buncombe County, and Approving Rates
W-1011 (2-24-93)

Wellington Mobile Home Park, Inc. - Recommended Order Granting Franchise to Furnish Water and Sewer Utility Service in Wellington Mobile Home Park Subdivision, Buncombe County, and Approving Rates
W-1011 (6-2-93) Order Adopting Recommended Order (6-2-93)

White Springs Water System, Inc. - Recommended Order Granting Franchise to Furnish Water utility Service in White Plains Subdivision, Cleveland County, and Approving Rates
W-1023 (5-27-93)

<u>COMPLAINTS</u>

CWS Systems, Inc. - Order Keeping Docket Open for Six Months in Complaint of James P. Supple
W-778, Sub 15 (2-10-93)

CWS Systems, Inc. - Order Closing Docket in Complaint of James P. Supple
W-778, Sub 15 (8-17-93)

ORDERS AND DECISIONS LISTED

CWS Systems, Inc. - Order Reopening Docket in Complaint of James P. Supply, and Scheduling Hearing for October 7, 1993, at 1:00 p.m.
W-778, Sub 15 (9-17-93)

CWS Systems, Inc. - Final Order Overruling Exceptions in Complaint of James P. Supple, and Affirming Recommended Order
W-778, Sub 15 (12-21-93) Errata Order (12-23-93)

CWS Systems, Inc. - Recommended Order in Complaint of James P. Supple
W-778, Sub 15 (11-12-93)

CWS Systems, Inc. - Novelle McCoy - Order Correcting Docket Number and Company Name in Complaint of Novelle McCoy
W-354, Sub 124; W-778, Sub 16 (2-1-93)

CWS Systems, Inc. - Order Dismissing Complaint of Novella McCoy and Douglas Wayne Ricks, Affordable Stick Built Homes, Inc., and Closing Docket
W-778, Sub 16 (5-4-93)

CWS Systems, Inc. - Order Allowing Dismissal of Complaint without Prejudice and Closing Docket in Complaint of Southland Associates, Inc.
W-778, Sub 18 (11-12-93)

Carolina Water Service, Inc. of North Carolina - Final Order Affirming Recommended Order in Complaint of Ed Meyerhoeffer
W-354, Sub 98 (2-2-93)

Carolina Water Service, Inc..of North Carolina - Recommended Order on Remand in Complaint of John R. and Margaret Hanway
W-354, Sub 112 (4-28-93)

Carolina Water Service, Inc. of North Carolina - Final Order Overruling Exceptions and Affirming Recommended Order on Remand in Complaint of John R. and Margaret Hanway
W-354, Sub 112 (6-11-93)

Carolina Water Service, Inc., of North Carolina - Recommended Order Granting Complaint in Part in Complaint of Sugar Mountain Resort, Inc.
W-354, Sub 116 (9-30-93)

Carolina Water Service, Inc. of North Carolina - Recommended Order Granting Complaint in Part of Sportsworld
W-354, Sub 117 (3-17-93)

Carolina Water Service, Inc. of North Carolina - Order Approving Billing Credit Calculation in Complaint of Sportsworld
W-354, Sub 117 (4-13-93)

Carolina Water Service, Inc. of North Carolina - Order Closing Docket in Complaint of Thomas Barnes
W-354, Sub 120 (8-12-93)

Carolina Water Service, Inc. of North Carolina - Order Requiring Customer Reconnection in Complaint of Novella McCoy and Douglas Wayne Ricks
W-354, Sub 124 (1-22-93)

Carolina Water Service, Inc. of North Carolina - Order Closing Docket in Complaint of Mrs. Janet Crompton
W-354, Sub 125 (5-26-93)

Fisher Utilities, Inc. - Order Closing Docket in Complaint of Steve Davidson
W-365, Sub 31 (11-2-93)

Fisher Utilities - Order Canceling Hearing and Holding Docket Open in Complaint of Jimmie Pennell
W-365, Sub 32 (9-29-93)

Green Spring Valley Mobile Estate - Order Dismissing Complaint of Mr. and Mrs. Charles Taylor and Closing Docket
W-897, Sub 2 (4-8-93)

Heater Utilities - Order Closing Docket in Complaint of Nelson Metke
W-274, Sub 79 (11-22-93)

Holiday Island Property Owners Association - Recommended Order Denying Complaint of T. E. Oatley
W-386, Sub 9 (10-29-93)

Hudson-Cole Development Corporation - Order Allowing Withdrawal of Complaint and Closing Docket in Complaint of Cole Park Plaza Associates Limited Partnership
W-875, Sub 3 (2-9-93)

Hunt Farms - Order Closing Docket in Complaint of Steve D. Harvell
W-931, Sub 1 (7-15-93)

Mid South Water Systems - Order Closing Docket in Complaint of Frank M. Williams III
W-720, Sub 124 (1-13-93)

Mid South Water and Sewer Systems, Inc. - Order Dismissing Complaint with Prejudice in Complaint of James A. Jennings, d/b/a River City Marina, Inc.
W-720, Sub 132 (10-15-93)

North State Utilities, Inc. - Order Scheduling Hearing on Complaint and Petition to Abandon on July 26, 1993, in Complaint of Piney Mountain Homeowners Association, Inc.; Order Appointing Emergency Operator for Piney Mountain
W-848, Sub 15; W-848, Sub 16 (7-14-93)

North State Utilities, Inc. - Order Granting Emergency Authority Pursuant to G.S. 62-116 in Complaint of Piney Mountain Homeowners Association, Inc.
W-848, Sub 15; W-848, Sub 16 (8-27-93)

North State Utilities, Inc. - Final Order Affirming and Adopting Recommended Order Appointing Emergency Operators and Approving Interim Rates in Complaint of Piney Mountain Homeowners Association, Inc.
W-848, Sub 15; W-848, Sub 16 (9-27-93)

North Topsail Water and Sewer, Inc. - Recommended Order Granting Complaint of William T. Davis, Lisa H. Davis, Michael S. Davis, Sherri G. Davis, and Joseph D. Davis
W-754, Sub 13 (10-19-93)

North Topsail Water & Sewer - Order Dismissing Complaints of Homer J. & Cheri L. Prince, and David W. Stone, and Closing Docket
W-754, Sub 15 (5-26-93)

Ross, Sanford E. - Recommended Order Requiring Improvements in Complaint of Teresa Lehman
W-618, Sub 2; W-618, Sub 3 (1-15-93)

Scotland Water Company and Randy Johnson - Order Dismissing Show Cause Proceeding in Complaint of Rose Lawson, and Closing Docket
W-426, Sub 3 (5-6-93)

Surry Water Company - Order Dismissing Complaint of Kim Pedersen, and Closing Docket
W-720, Sub 126; W-314, Sub 28 (5-26-93)

Wendell Transport Corporation - Order Granting Motion for Protective Order in Complaint of North Carolina Intrastate Petroleum Rate Committee of the North Carolina Trucking Association, Inc.
T-1039, Sub 19 (3-8-93)

DISCONTINUANCE OF SERVICE

Carolina Water Service, Inc., of North Carolina - Order Granting Discontinuance of Water Service in Coastal Mobile Estates Subdivision, Carteret County, and Requiring Customer Notice
W-354, Sub 131 (11-24-93)

Crater Brothers, Inc. - Order Authorizing Discontinuation of Water Utility System Serving Crater Park Subdivision, Mecklenburg County, Canceling Hearing, and Requiring Public Notice
W-185, Sub 3 (10-5-93)

East Rutherford Water System, Inc. - Order Approving Discontinuance of Water Utility Service in Crestview Subdivision, Rutherford County, and Requiring Notice to Customers
W-527, Sub 4 (8-10-93)

Hidden Valley Campground Estates and Campground Water Systems - Order Authorizing Disconnection of Service for Nonpayment of Water Utility Bills
W-915, Sub 1 (2-9-93)

Hidden Valley Campground Estates and Campground Water Systems - Order Authorizing Permanent Disconnection of Service for Nonpayment of Water Bills
W-915, Sub 1 (7-22-93)

Huffman Water System, Inc. - Order Authorizing Discontinuation of Water Utility Service in Crestmont Subdivision, Catawba County
W-95, Sub 16 (7-21-93)

Killian Water System - Order Authorizing Discontinuation of Service in Crestmont Subdivision, Catawba County
W-298, Sub 3 (6-4-93)

Mid South Water System, Inc. - Order Approving Discontinuance of Water Utility Service in Hickory Woods Subdivision, Catawba County, and Requiring Notice to Customers
W-720, Sub 127 (5-18-93)

Mid South Water Systems, Inc. - Order Authorizing Discontinuance of Water Service in Westview Acres Subdivision, Burke County, and Requiring Notice to Customers
W-720, Sub 131 (11-24-93)

Piedmont Carolina Construction, Inc. - Order Authorizing Discontinuation of Water Utility System Serving Eastbrook Acres Subdivision, Catawba County, Canceling Hearing, and Requiring Public Notice
W-768, Sub 3 (10-5-93)

Santeetlah Shores Water System - Order Authorizing Disconnection of Service for Nonpayment of Water Utility Bills
W-577, Sub 1 (3-5-93)

Scottish Real Estates, Inc., and Sam Pressley - Order Authorizing Discontinuation of Water Service in Walnut Hills Subdivision, Cabarrus County
W-985 (12-1-93)

EMERGENCY OPERATOR

Bradfield Farms Utility Company - Order Appointing Emergency Operator, to Provide Water and Sewer Utility Service in Bradfield Farms and Silverton Subdivisions, Mecklenburg and Cabarrus Counties, Approving Rates, and Clarifying Order
W-1026 (10-27-93)

Glen Ray Heights Subdivision - Order Appointing Johnny R. Morgan as Emergency Operator for Glen Ray Heights Subdivision, Rowan County, and Approving Rates
W-1041 (9-17-93)

Hidden Valley Campground Estates Water Systems - Recommended Order Authorizing Abandonment of Water System Effective July 1, 1993 - HydroLogic, Inc., Emergency Operator
W-915, Sub 1 (4-27-93)

Rayco Utilities, Inc. - Recommended Order Denying Complaint and Requesting Rayco Utilities, Inc., to Serve as Emergency Operator
W-899, Sub 11 (3-29-93)

Rayco Utilities, Inc. - Order Appointing Emergency Operator for Sewer Franchise in Graystone Forest Subdivision, Forsyth County, and Authorizing Rates
W-899, Sub 11 (5-21-93)

Sedgefield Development Corporation - Order Declaring Real Emergency, Granting Emergency Authority Pursuant to G.S. 62-116(b) and Scheduling Show Cause Hearing in Durham on June 22, 1993
W-1036 (6-11-93)

MERGER

Fairways Utilities, Inc. - Order Approving Merger with Inlet Bay Utilities, Inc.
W-787, Sub 3 (10-27-93)

RATES

Alpha Utilities, Inc. - Interlocutory Order Granting Interim Rates for Water utility Service in All Its Service Areas in North Carolina
W-862, Sub 14 (1-29-93)

Blue Farm Water System - Order Approving Contracts to Increase Rates for Water Utility Service in Blue Farms Subdivision, Moore County
W-926, Sub 1 (1-20-93)

Bradfield Farms Utility Company - Order Correcting Schedule of Rates in Bradfield Farms and Silverton Subdivisions, Mecklenburg and Cabarrus Counties
W-1026 (10-29-93)

Brookwood Water Corporation - Recommended Order Approving Partial Increase in Rates for Providing Water Utility Service in All Its Service Areas in North Carolina
W-177, Sub 36 (5-21-93) Order Allowing Recommended Order to Become Effective (5-21-93)

Cardinal Estates Water System - Recommended Order Granting Partial Rate Increase for Water Utility Service in Cardinal Estates Subdivision, Catawba County
W-701, Sub 1 (10-28-93)

Carolina Trace Corporation - Order on Remand Reopening Hearing to Increase Rates for Providing Water and Sewer Utility Service in Carolina Trace Subdivision, Lee County
W-436, Sub 4 (5-10-93)

Carolina Water Service, Inc. of North Carolina - Order Amending Schedule of Rates to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina
W-354, Sub 111 (4-13-93)

ORDERS AND DECISIONS LISTED

Corriher Water Service, Inc. - Recommended Order Granting Partial Increase in Rates for Water Utility Service for All Its Service Areas in North Carolina
W-233, Sub 15 (7-22-93)

Crabtree Water Systems - Order Granting Rate Increase for Water Utility Service in Crabtree II Subdivision, Catawba County, Canceling Hearing, and Requiring Public Notice
W-967, Sub 2 (6-1-93)

4 Seasons Mohovilla Utilities, G. P. McConiga, d/b/a - Recommended Order Granting Rate Increase for Water Utility Service in 4 Seasons Mohovilla Mobile Home Park, Lenoir County
W-1002 (2-3-93)

Goss Utility Company - Recommended Order Granting Rate Increase in All Its Service Areas, Chatham, Durham, and Person Counties
W-457, Sub 11 (2-16-93)

Harrco Utility Corporation - Recommended Order Granting Partial Rate Increase for Sewer Utility Service in Its Service Areas, Durham and Wake County, and Suspending Connections
W-796, Sub 7 (1-12-93) Order Modifying Recommended Order (3-31-93)

Hunter Water Company - Recommended Order to Increase Rates for Water Service in Parkwood and Huntwood Subdivisions
W-534, Sub 1; W-534, Sub 2 (10-5-93)

Hydraulics, Ltd. - Recommended Order Granting Partial Rate Increase for Water Utility Service in All of Its Service Areas in North Carolina
W-218, Sub 88 (7-29-93)

Hydraulics, Ltd. - Order Approving Interim Rates for Water Utility Service in All of Its Service Areas in North Carolina
W-218, Sub 88 (8-20-93)

Inlet Bay Utilities, Inc. - Recommended Order Granting an Increase in Rates for Water and Sewer Utility Service in its Service Areas, New Hanover County
W-828, Sub 7 (4-21-93)

Johnston-Wake Utilities, Inc. - Order Granting Rate Increase for Water Utility Service in all Its Service Areas in Wake and Johnston County, and Requiring Public Notice
W-906, Sub 4 (10-29-93)

Joyceton Water Works, Inc. - Order Granting Rate Increase for Water Utility Service in All Its Service Areas in Caldwell County, and Requiring Public Notice
W-4, Sub 5 (10-12-93)

Lee, Ira D. & Associates, Inc. - Recommended Order to Increase Rates for Providing Water and Sewer Utility Service in All Its Service Areas, Wake County
W-876, Sub 2 (2-12-93)

Linville Ridge - Order Granting Rate Increase for Water Utility Service in Linville Ridge Subdivision, Avery County, Canceling Hearing, and Requiring Public Notice
W-766, Sub 2 (12-1-93)

Mid South Water Systems, Inc. - Order Denying Motion for Interim Rate Authority for Sewer Utility Service in All Its Service Areas in North Carolina
W-720, Sub 119 (4-27-93)

North Topsail Water and Sewer, Inc. - Interlocutory Order Reducing Interim Sewer Rates in All Its Service Areas in Onslow County, Effective November 1, 1993
W-754, Sub 12; W-754, Sub 17 (10-8-93) Errata Order (10-15-93)

Pied Piper Resort Water System - Final Order Approving Rates and Assessment and Disconnection Policy
W-893, Sub 1 (5-26-93)

Piedmont Construction and Water Company, Inc. - Recommended Order Approving Rate Increase in Duan Acres Subdivision, Catawba County
W-262, Sub 42 (8-10-93)

Prior Construction Company, Inc. - Recommended Order Relating to Water Service Problems to Increase Rates for Water Utility Service in All of Its Service Areas, Wake County
W-567 (7-23-93)

River Run Utilities, Inc. - Recommended Order Granting Partial Increase in Rates for Providing Sewer Utility Service in River Run Shopping Center, Brunswick County
W-853, Sub 2 (5-19-93)

Sedgefield Development Corporation - Recommended Order Finding Utility Status, Continuing Emergency Authority, and Setting Rates
W-1036 (8-26-93)

Sedgefield Development Corporation - Order Approving Schedule of Rates
W-1036 (9-2-93)

ST Utility Company - Order Granting Partial Rate Increase for Sewer Utility Service in Oyster Bay Subdivision, Brunswick County
W-984, Sub 1 (7-23-93)

Woodlake Water and Sewer Company, Inc. - Interlocutory Order Granting Interim Rates to Provide Water and Sewer Utility Service in Woodlake Country Club, Moore County, from Woodlake Partners, d/b/a Woodlake Country Club
W-1029 (6-21-93)

ORDERS AND DECISIONS LISTED

SALES AND TRANSFERS

All Star Mobile Home Park, John Buffalo, d/b/a - Recommended Order Approving Transfer of Water System from John Buffalo and Wife to the Conly Drive Owners Association, Inc.
W-628, Sub 2 (10-27-93)

Bayview Water Works, Harriet R. Ross, d/b/a - Order Granting Transfer of Water Utility System in Bayview Subdivision, Beaufort County, to Bayview Homeowners Association, Inc., (Owner Exempt from Regulation) and for Authority to Discontinue Providing Water Utility Service in Same
W-565, Sub 5; W-565, Sub 6 (12-15-93)

Burnett Utilities, Inc. - Order Approving Transfer of Ownership of Its Water and Sewer Utility Systems, Mecklenburg County to the City of Charlotte (Owner Exempt from Regulation)
W-892, Sub 10 (6-3-93)

Crabtree Water Systems - Order Granting Transfer of Franchise to Provide Water Utility Service in Deerwood Subdivision, Lincoln County, from W & K Enterprises, Approving Rates, and Canceling Hearing
W-967, Sub 1 (10-6-93)

First Citizens Bank & Trust Company - Order Approving Transfer of Control and Ownership of Intracoastal Utilities, Inc., from Pioneer Savings Bank, Inc.
W-986, Sub 1 (9-22-93)

Forest Hills Water System - Recommended Order For Allowing Transfer of Franchise to Provide Water Utility Service in Forest Hills Subdivision, Surry County, from James W. Partin & Worth Winebarger, d/b/a Forest Hills Water System
W-935, Sub 2 (4-28-93)

Heater Utilities, Inc. - Recommended Order Approving Transfer of the Franchise to Provide Water utility Service in Heritage Point Subdivision, Wake County, from Heritage Water Company, Inc., and Granting Increased Rates
W-274, Sub 69 (3-1-93)

Hickory Hills Service Company, Inc. - Order Approving Transfer of Ownership of the Water Utility System Serving Hickory Hills Subdivision, Lenoir County, to the City of Kinston (Owner Exempt from Regulation
W-460, Sub 6 (10-13-93)

Johnson Properties, Inc. - Recommended Order Approving Transfer of Franchise to Provide Water Utility Service in Lake Royale Subdivision, Franklin County, from Riviera Utilities of North Carolina, Inc.
W-1030 (6-15-93)

Mid South Water Systems, Inc. - Order Granting Transfer of the Water Utility System in South Pointe at Landen Subdivision, Mecklenburg County, to Union County Public Works Department (Owner Exempt from Regulation)
W-720, Sub 128 (6-23-93)

North Wilmington Service Company, Ammons Northchase Corporation, d/b/a - Order Approving Transfer of Its Water and Sewer Utility Service in NorthChase Subdivision, New Hanover County, to New Hanover County (Owner Exempt from Regulation), and Requiring Public Notice
W-963, Sub 2 (11-18-93)

Ogden Village Utilities, Inc. - Order Approving Transfer of Sewer Utility Service in Ogden Village Shopping Center, New Hanover County, to New Hanover County (Owner Exempt from Regulation), and Requiring Public Notice
W-836, Sub 3 (10-20-93)

Rock Barn Water System - Order Approving Transfer of the Water Utility System in Rock Barn Subdivision, Catawba County, to the City of Conover (Owner Exempt from Regulation), and Requiring Public Notice
W-747, Sub 3 (7-21-93)

Scotsdale Water and Sewer, Inc. - Order Approving Transfer of Franchise to Provide Water Utility Service in Hunt Farms Subdivision, Wake County, from James A. Burnett, Jr., and Ronald D. Burnett, d/b/a Hunt Farms, and Approving Rates, Requiring Improvements, and Requiring Public Notice
W-883, Sub 18 (12-15-93)

Sea Isle Hills Water Systems - Order Granting Transfer of Water Utility System in Sea Isle Hills Subdivision, Dare County, to Sea Isle Hills Water Association, Inc., (Owner Exempt from Regulation)
W-900, Sub 1 (12-22-93)

Serenity Point Condominium Association Utilities, Inc. - Recommended Order Approving Transfer to Provide Sewer Utility Service in Serenity Point Subdivision, Pender County, from C & L Utilities Inc., and Approving Rates
W-995 (1-25-93)

Southland Associates, Inc. - Recommended Order Approving Transfer of Franchise to Provide Water Utility Service in Hardscrabble Subdivision, Durham County, from Harrco Utility Corporation
W-1031 (4-29-93)

Twin Valley Water System, B. E. Mathews Construction Company, Inc., d/b/a - Order Approving Transfer of Water Utility System in Twin Valley Subdivision, Catawba County, to the City of Conover (Owner Exempt from Regulation)
W-641, Sub 3 (8-25-93)

Water Resources, Inc. - Recommended Order Approving Transfer of Franchise for Water utility Service in Rocky River Subdivision, Cabarrus County, and Wiltshire Manor Subdivision, Mecklenburg County, from General Utilities Associates
W-1034 (9-16-93)

Waverly Mills, Inc. - Order Approving Transfer of Its Water and Sewer Utility Systems in the Town of Laurinburg to the City of Laurinburg (Owner Exempt from Regulation)
W-734, Sub 3 (1-13-93)

West Wilson Water Corporation - Order Approving Transfer of the Water Utility System in Sherwood Forest Subdivision, Wilson County, to the City of Wilson (Owner Exempt from Regulation)
W-781, Sub 18 (7-8-93)

SECURITIES

Heater Utilities, Inc. - Order Approving Financing of $8.0 Million and Pledging of Assets
W-274, Sub 77; W-177, Sub 37 (6-14-93)

North Topsail Water and Sewer Inc. - Order Authorizing Placing of Stock in Trust or Escrow
W-754, Sub 12; W-754, Sub 17 (11-10-93)

TARIFFS

Blue Creek Utilities, Inc. - Order Approving Tariff Revision to Establish a Tap Fee for Commercial Customers in All of Its Service Areas in Onslow County
W-857, Sub 4 (9-2-93)

CWS Systems, Inc. - Order Approving Tariff Revision to Increase Rates for Sewer Utility Service for Increased Cost of Bulk Sewage Treatment in Fairfield Mountains Development, Rutherford County
W-778, Sub 19 (6-30-93) Errata Order (8-17-93)

Heater Utilities, Inc. - Order Amending Tariff to Increase Rates for Water Utility Service in All Its Service Areas in North Carolina
W-274, Sub 75 (9-17-93)

Johnson Properties, Inc. - Order Approving Tariff Revision to Implement a Late Charge Fee and a NSF Check Fee for All Customers in the Lake Royale Subdivision, Franklin County
W-1030, Sub 1 (9-21-93)

Mid South Water Systems, Inc.; Surry Water Company, Inc.; Lincoln Water Works, Inc.; Huffman Water Systems, Inc. - Order Amending Tariff to Include Cut Valve Replacement Fee
W-720, Sub 125; W-314, Sub 27; W-335, Sub 5; W-95, Sub 15 (5-28-93)

Mobile Hill Estates Water System - Order Granting Tariff Revision to Increase Rates for Water Utility Service Due to Lead/Copper Testing Expense for Mobile Hill Estates, Wake County
W-224, Sub 10 (8-11-93)

Piedmont Construction and Water Company, Inc. - Order Approving Tariff Revision to Increase Rates for Water Utility Service Due to Increased Expenses Related to Recently Implemented EPA Mandated Testing Requirements and DEHNR Operating Permit Fees
W-262, Sub 47 (9-22-93)

Scotsdale Water and Sewer Company, Inc. - Recommended Order Denying New Customer Fee
W-883, Sub 17 (11-3-93)

Scotsdale Water and Sewer Company, Inc. - Order Granting Tariff Revision to Increase Rates for Water Utility Service Due to Lead/Copper Testing Expense
W-883, Sub 19 (8-18-93)

Stately Pines Utilities, Inc. - Order Approving Tariff Amendment to Add a Commercial Sewer Tap-on Fee
W-968, Sub 1 (2-10-93)

Watercrest Estates - Order Approving Tariff Revision to Increase Rates for Water and Sewer Utility Service for Increased Cost of Bulk Water and Sewage Treatment and New Testing Costs in Watercrest Estates Mobile Home Park, Iredell County
W-1021, Sub 1 (8-25-93)

TEMPORARY OPERATING AUTHORITY

Thompson, Donald O. - Recommended Order Granting Temporary Operating Authority to Furnish Water Utility Service in Camelot Subdivision, Henderson County, and Approving Rates
W-1024 (4-27-93)

MISCELLANEOUS

Alpha Utilities - Order Restricting Water Use and Requiring Public Notice
W-862, Sub 16 (7-8-93)

Apple Lane Mobile Court, J. M. Yost, d/b/a - Order Requiring Refunds
W-514, Sub 2 (2-17-93)

Barrier Grain Company - Order Cancelling Hearing, Requiring Public Notice and Closing Docket
W-688, Sub 3 (1-19-93)

Bear Den Acres Development, Inc. - Recommended Order Declaring Utility Status, Setting Interim Rates, and Requiring Bond and Public Notice
W-1040 (11-15-93)

Bogue Banks Water Corporation - Order Authorizing Construction Expenditures
W-371, Sub 2 (1-27-93)

Bogue Banks Water Corporation - Order Approving 1993-1994 Budget
W-371, Sub 4 (6-1-93)

Bogue Banks Water and Sewer Corporation - Order Changing Fiscal Year
W-371, Sub 5 (8-5-93)

Bogue Banks Water Corporation - Order Approving 1994 Budget
W-371, Sub 6 (12-22-93)

Bradfield Farms Utility Company - Order Authorizing Pace Development Group to Employ Mid South Water Systems, Inc., as an Independent Contractor
W-1026 (11-30-93)

CWS Systems, Inc. - Order Authorizing Release of Bond Upon Compliance with Conditions
W-778, Sub 8 (10-26-93)

Cape Fear Utilities, Inc. - Order Accepting Report and Canceling Sewer Franchises
W-279, Sub 22; W-279, Sub 24 (4-15-93)

Carolina Water Service, Inc. of North Carolina - Protective Order
W-354, Sub 128 (12-21-93)

Carolina Water Service, Inc. of North Carolina - Order Requiring Immediate Reconnection of Customers in Coastal Mobile Estates
W-354, Sub 130 (10-13-93)

Carolina Trace Corporation - Order of Clarification
W-436, Sub 4 (On Remand) (6-30-93)

Carolina Trace Corporation - Order Canceling Hearing Pending Ruling on Settlement Proposal for Authority to Increase Rates for Providing Water and Sewer Utility Service in Carolina Trace Subdivision, Lee County
W-436, Sub 4 (9-13-93) (On Remand)

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